

TECHNICAL PROGRESS REPORT NO. 16 JULY-SEPTEMBER 1996

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TECHNICAL PROGRESS REPORT NO. 16 JULY-SEPTEMBER 1996

U.S. DEPARTMENT OF ENERGY
PITTSBURGH ENERGY TECHNOLOGY CENTER
CONTRACT DE-AC22-92PC92159

FOR

ENGINEERING DEVELOPMENT OF ADVANCED COAL-FIRED
LOW-EMISSION BOILER SYSTEMS

SUBMITTED BY:

ABB POWER PLANT LABORATORIES
COMBUSTION ENGINEERING, INC.

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APPENDIX B Technical Paper - "ABB's LEBS Activities - A Status Report"

APPENDIX C Technical Paper - "The ABB LEBS System Design"

APPENDIX D Technical Paper - "Advancements in Low NO_x Firing Systems"

APPENDIX E "Corrosion and Deposition in Reducing Environments"

EXECUTIVE SUMMARY

INTRODUCTION

The Pittsburgh Energy Technology center of the U.S. Department of Energy (DOE) has contracted with Combustion Engineering, Inc. (ABB CE) to perform work on the "Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems" Project and has authorized ABB CE to complete Phase I on a cost-reimbursable basis and Phases II and III on a cost-share basis.

The overall objective of the Project is the expedited commercialization of advanced coal-fired low-emission boiler systems. The specified primary objectives are:

	Preferred Performance	Minimum Performance
NO _x Emissions, lb/million Btu	0.1	0.2
*SO ₂ Emissions, lb/million Btu	0.1	0.2
Particulate Emissions, lb/million Btu	0.01	0.015
Net Plant (HHV) Efficiency, %	42	38

*3 lb S/million Btu in the coal

The specific secondary objectives are:

- Improved ash disposability.
- Reduced waste generation.
- Reduced air toxics emissions.

The final deliverables are a design data base that will allow future coal-fired power plants to meet the stated objectives and a preliminary design of a Commercial Generation Unit.

The work in Phase I covered a 24-month period and included system analysis, RD&T Plan formulation, component definition, and preliminary Commercial Generating Unit (CGU) design.

The work in Phase II covered a 24-month period and included preliminary Proof-of-Concept Test Facility (POCTF) design and subsystem testing.

Phase III will cover a 6-month period beginning October 1, 1996 and will produce a revised CGU design and a revised POCTF design, cost estimate and a test plan.

Phase IV, the final Phase, will cover a 36-month period and will include POCTF detailed design, construction, testing, and evaluation.

The project is being managed by ABB CE as the contractor and the work is being accomplished and/or guided by this contractor, the DOE Contracting Officer's Representative (COR) and the following team members:

Subcontractors and Suppliers

- ABB Combustion Engineering Systems (ABBES)
- ABB Environment Systems, Inc. (ABBES)
- Raytheon Engineers and Constructors, Inc. (RE&C)

Consultants

- Dr. Janos Beér, MIT
- Dr. Jon McGowan, U. of Mass.

Advisors

- Association of Edison Illuminating Companies - Power Generation Committee (AEIC)
- Advanced Energy Systems Corporation (AES)
- Black Beauty Coal Company
- Electric Power Research Institute (EPRI)
- Illinois Clean Coal Institute (ICCI)
- Peridot Chemicals, Inc.
- Richmond Power & Light (RP&L)
- Southern Company Services, Inc. (SCS)

SUMMARY

The Project is under budget and generally on schedule. The current status is shown in the Milestone Schedule Status Report included as Appendix A.

Technology transfer activities included delivering technical papers at three conferences (Appendices B, C and D) and submitting a paper abstract for another conference.

Under Task 7 - Component Development and Optimization the CeraMem filter testing was completed. Due to an unacceptably high flue gas draft loss, which will not be resolved in the POCTF timeframe, a decision was made to change the design of the flue gas cleaning system from Hot SNO_xTM to an advanced dry scrubber called New Integrated Desulfurization (NID). However, it is recognized that the CeraMem filter still has the potential to be viable in pulverized coal systems.

In Task 8 - Preliminary POCTF Design integrating and optimizing the performance and design of the boiler, turbine/generator and heat exchangers of the Kalina cycle as well as the balance of plant design were completed. Licensing activities continued. A NID system was substituted for the SNO_x Hot Process.

Work was completed in Task 9 - Subsystem Test Design and Plan in an earlier reporting period.

Task 10 - Subsystem Test Unit Construction - The test rig for the 5,000 acfm CeraMem test has been returned to CeraMem.

Task 11 work on the CeraMem filter was deleted. DOE comments were received on the draft reports for Subtasks 11.2 and 11.3 and final reports were issued.

Task 12 work on the Phase II Report was initiated.

Plans for the next reporting period include: issuing Subtask 8.2 and Phase II reports and starting work on Phase III.

TASK 1 - PROJECT PLANNING AND MANAGEMENT

The Project is under budget and generally on schedule. The current status is shown in the Milestone Schedule Status Report included as Appendix A. All work in Task 1 and all Task 1 deliverables for the reporting period were completed on schedule. All quarterly reports and all monthly Status, Summary, Milestone Schedule Status, and Cost Management reports were submitted on schedule.

Technology transfer activities consisted of the following:

- A paper titled "ABB's LEBS Activities - A Status Report" was delivered at the First Joint Power and Fuel Systems Contractors Conference. (Appendix B)
- A paper titled "The ABB LEBS System Design" was delivered at the 13th Annual International Pittsburgh Coal Conference. (Appendix C)
- An abstract of a paper was submitted for the 22nd International Technical Conference on Coal Utilization & Fuel Systems.
- A paper titled "Advancements in Low-NO_x Firing Systems" was delivered at the Institute of Clean Air Companies Forum 96 in Baltimore in March. (Appendix D)

TASK 7 - COMPONENT DEVELOPMENT AND OPTIMIZATION

SNO_xTM Hot Process

The 500 hour test on non-catalytic filters was completed and operation was terminated 12 Aug 96. The unit was operated for approximately 450 hours on flue gas. Particulate removal was successful.

The filter was cleaned successfully, as evidenced by regeneration of tubesheet pressure differential. However, tubesheet differential pressure was higher than expected and increased with operating time.

Unit was operated at the following conditions:

- Filtration temperature - approx. 650-675 F.
- Filter Face Velocity - approx. 2.5 - 4.5 ft/min.
- Cleaning pulse duration - 200 ms.
- Pulse dwell - 15 minutes, complete cycle (alternate firing of opposing solenoids fire on 7.5 minute schedule), extended to final value of 30 minutes, complete cycle (alternating firing of opposing solenoids every 15 minutes)

Tubesheet differential pressure started at approximately 8 inches water at filter face velocity (FFV) = 4 and rose to approximately 12 inches water at FFV = 4. Tubesheet differential pressure stabilized at this value. At the end of half-dwell time, tubesheet differential pressure increased approximately 0.5-0.75 inch w.c.

The unit was dismantled and shipped to Pennsylvania State University per DOE request. On inspection, tubesheet "clean-side" did not show any evidence of ash, particularly in cracks and crevices.

Filters were removed from the unit and inspected. "Clean-side" and "dirty-side" of filters were as expected. Each cell was plumbed with a guitar string to check for plugs. No channels (out of 684 total) were found to be plugged. The filters were shipped to CeraMem for further analysis.

Low-NO_x Firing System

Completed. (See Appendix E for ABB's report on "Corrosion and Deposition in Reducing Environments".)

TASK 8 - PRELIMINARY POC TEST FACILITY DESIGN

8.1 - Site Selection

In October of 1994 ABB CE formally accepted the Richmond Power & Light (RP&L) offer of Whitewater Valley Unit No. 1 as the host site for the Proof-of-Concept Test Facility (POCTF).

8.2 - Preliminary Design

The proposed POCTF design is a repowering of Richmond (Indiana) Power & Light (RP&L) Whitewater Valley Unit 1 (WV #1) with the LEBS technologies. Equipment between the coal bunker outlets and stack inlet along with the turbine/generator will be replaced. The design includes an optimized TFS 2000TM firing system, a Kalina Cycle and a New Integrated Desulfurization (NID) system which were described in earlier reports. The major subsystems in the Kalina cycle are the boiler or "vapor generator," the turbine/generator and the heat exchangers. Work on these subsystems is finished. The overall plant design was the major activity during the reporting period.

Design Basis

The basis of the facility design is the Kalina cycle heat balance prepared by Exergy, and the equipment designs prepared by ABB to implement the cycle:

- Vapor generator
- Turbine-generator
- Cycle heat

and the flue gas treatment process and equipment,

- NID system.

These systems are not described here but are incorporated in the overall project documentation identified in Task 12.

Process Description

To identify the overall facility configuration and quantify key process flow variables, the following process flow diagrams were developed:

- gas-side heat balance,
- turbine heat balance,
- water balance, and
- ammonia balance.

The first two of these diagrams are shown in Figures 1 and 2.

Plant Performance

The primary technical parameters for the facility, that characterize its design and performance, are listed in Table 1.

The design-basis values of primary plant emission rates are listed in Table 2. It is emphasized that these are not guarantee values, nor are they values for which the facility will be licensed; rather, they are target values and they provide the design basis for the associated systems and equipment.

Plant Arrangements

The overall arrangement of the POCTF is shown in the attached plot plan, Figure 3.

The new boiler system is located in the existing boilerhouse (following demolition of the existing boiler), and the new turbine-generator system is located in the existing turbine hall (following similar demolition). A new building, the heat exchanger building, will be erected adjacent to the west side of the turbine hall to house the Kalina cycle heat exchangers and most of the new electrical distribution equipment.

Outside, a new flue gas area will be established to accommodate the air heater, FD/ID fans, and NID system components. This area will be located adjacent to the southwest corner of the boilerhouse. The flue gas ductwork will leave the boilerhouse on the west side, connect to the final heat recovery and gas cleanup equipment in the flue gas area, and then be routed up onto the boilerhouse roof to mate with the existing flue gas ductwork (see Figure 4).

Also located outside in the yard area will be various auxiliary systems, such as (fresh) ammonia storage, spent ammonia capture and recovery, and auxiliary steam.

Project Scope

The major elements of the facility design are summarized in the following listing and are discussed in the subsequent sections.

- Demolition of Existing Unit 1 Facilities
- Mechanical/Power Systems
 - 12 New Heat Cycle Systems
 - 10-15 New Auxiliary Systems
 - New Mechanical Services Systems (HVAC, fire protection, drainage)
 - 5-10 Modified Systems
- Process Systems
 - Modified Demin Water Production
 - Cycle Fluid Treatment: Chemical/Physical
- Electrical
 - High Voltage System (14.4 kV)
 - AC Distribution Systems
 - UPS & DC Systems (extend existing)
 - Lighting / Grounding / In-Plant Communications
- Civil / Structural
 - Site Preparation
 - Modify T/G Pedestal
 - Modify Boiler Support System & Boilerhouse
 - Heat Exchanger Building
 - Outside Foundations
 - Modify Circulating Water Flume
- Instrumentation & Control
 - New Distributed Control System (DCS)
 - New Instrumentation and Control Elements

Demolition

Budgetary bids were received from two demolition contractors, following their walk-down of the site and the work areas. In addition to budgetary costs, the contractors also submitted estimated schedules and described their approach to the work.

The largest concentration of work is in the boilerhouse. Removal of the boiler and its auxiliaries will therefore dictate the overall demolition schedule, which will require a minimum of six months, as this area is confined and thus limits the crew size that can be applied to the work.

Power Cycle Systems and Heat Exchangers

To perform the thermodynamic functions specified in the turbine heat balance (other than the vapor generator and turbine functions), the overall cycle has been divided into twelve individual systems, denoted as the Power Systems.

These twelve interconnecting systems, when integrated with the vapor generator and turbine, make up the Kalina cycle. The power systems are composed of the heat exchangers, pumps, vessels, piping, valves and in-line instrumentation required to perform the required thermal and fluid-separation functions. A piping and instrumentation diagram for a representative system is shown in Figure 5.

The critical components in the 12 power systems are the heat exchangers. A significant number of these devices are used, with the large majority providing regenerative heat transfer duty, and the balance performing final condensation and heat rejection. Outline drawings of the heat exchangers are shown in the composite sketch in Figure 6.

BOP Mechanical/Process Systems

To support operation of the primary power and process systems, a number of new auxiliary systems are needed. In some cases, these new systems replace existing systems that are being removed because they do not meet POCTF requirements. These new systems include:

- Vents and Drains - Vapor Generator
- Vents and Drains - Turbine
- Vents and Drains - Cycle Piping and Heat Exchangers
- Sootblowing Air
- Auxiliary Steam
- Auxiliary Condensate Collection
- Ammonia Storage and Distribution
- Closed Cooling Water
- Service Air
- Instrument Air

- Pump Seal Water
- Blowdown and Ammonia Recovery
- Ammonia / Water Sampling

In addition, the following existing auxiliary systems will be modified to meet POCTF design requirements:

- Circulating Water
- Flyash
- Bottom Ash
- Demineralized Water Treatment
- Demineralized Water Storage & Transfer
- Service Water
- Fuel Oil
- Plant Drains & Wastewater

A representative diagram, for the circulating water system, is shown in Figure 7.

Electrical System

The electrical system consists of two primary segments:

- the unit power generator and auxiliaries, which provides outgoing power to the utility's distribution network, and
- the auxiliary power system, including the existing direct current (DC) and uninterruptible power supply (UPS) systems, which serve the unit operating auxiliaries.

The major system equipment includes

Unit Generator System

- Generator
- Exciter and Excitation Equipment
- Generator Auxiliaries
- Isolated-Phase Bus Duct
- Generator Stepup Transformer
- Generator/Transformer Control and Protective Relay Panels

Auxiliary Power System

- Auxiliary Station Power Transformers
- Cable Bus
- Medium Voltage Switchgear
- Low Voltage Switchgear
- Low Voltage Motor Control Centers

The functional relationship of the major components of the electrical system are shown on the main single line diagram, Figure 8.

Control System

The new distributed control system (DCS) will consist of distributed processing units with I/O cards, operator and engineering workstations with CRT's, printers, and a redundant data highway for communications between components. The DCS will serve as the overall plant control system and will provide the operator with a single 'window' to the process. The functional arrangement of the system is shown on Figure 9.

The major system equipment includes distributed control units located throughout the plant, two operator's workstations with three CRT's, one engineer's workstation with a CRT, four printers, and a redundant fiber optic highway.

Structures

The primary new structure to be added is the Heat Exchanger Building. It will house the vertical and horizontal cycle heat exchangers that range in diameter from 3' to 8', and in length from 30' to 80'. The weights of these units range from 12 to 175 tons. This building will be a high-bay area (90' height), with approximate plan dimensions of 120' x 95', and will be located adjacent to the west side of the turbine hall.

The site soil conditions require caissons for support of the heat exchangers and building columns. A ground floor slab will be installed that will be supported from, and tied into, the caissons. Several pump pits and equipment support pads will be part of this slab construction. The structural framing for the building will be conventional Type 2, braced-steel construction.

The roof is provided with hatches over the vertical heat exchangers to facilitate future maintenance and tube bundle removal. The building columns are extended through the roof, up to the parapet level, to provide support for rigging/cranes on the roof for heat exchanger installation and tube bundle removal. Similarly, the north wall is

provided with louvres, both operating and dummy (fixed/insulated), that are located so that, when removed, the resulting openings will allow for installation/removal of the horizontal heat exchanger tube bundles.

The architectural features of the building are shown on Figure 10. These features include a combination of brick and metal siding, fixed and motor-operated louvres, and expansion joints where the new building abuts existing structures.

Licensing

The revised licensing plan (that includes NID and the Kalina cycle) was reviewed with RP&L's consul for environmental affairs, Mr. Tony Sullivan, and agreement was reached on how the project licensing will proceed.

A letter was submitted to IDEM requesting a determination of PSD nonapplicability for the project. The draft of the air permit application was completed and distributed for in-house comment. Work continued on preparation of the Risk Management Plan, associated with the use of ammonia in the plant.

TABLE 1
PLANT TECHNICAL SUMMARY

Power Cycle and Plant Performance

Net Generation Capacity	(kW)	47,350
Gross Generation Capacity	(kW)	54,590
Auxiliary Power	(kW)	7,250

Main Flow @ Turbine Throttle

Flow Rate	(lb/hr)	640,000
Ammonia Proportion	(wt%)	68.5
Temperature	(F)	1050
Pressure	(psig)	2400

Hot Reheat Flow @ Turbine

Flow Rate	(lb/hr)	302,300
Ammonia Proportion	(wt%)	68.5
Temperature	(F)	1050
Pressure	(psig)	338

Vapor Generator

Firing Rate	(MMBtu/hr)	455
Efficiency	(%)	87.7

Heat Rate

Unit Turbine Cycle	(Btu/kWh)	7,310
Net Unit	(Btu/kWh)	9,610
		(35.5% EFF.)

Operation

Type		Baseload
Expected Capacity Factor	(%)	80 (min.)

Coal Quality (Performance Coal)

Coal Name		Black Beauty
Classification		Bituminous
Higher Heating Value	(Btu/lb)	11,428
Short Proximate Analysis		
Moisture	(wt%)	13.0
Ash	(wt%)	8.1
Sulfur	(wt%)	3.4
S Content	(lb/MMBtu)	3.0

TABLE 1
(Cont'd)

Selected Equipment Options

Coal Handling (existing)	Truck Delivery
Power Cycle	Kalina
Working Fluid	Ammonia/Water
Vapor Generator	Drum Type
Firing System	Tangential
Feed Pump Drive	Motor
Air Heater	Rotary-Regenerative
Emissions Control	
NO _x	Combustion-Based
SO ₂	NID Process
Particulate	Pulse-Jet Fabric Filter
Turbine	2-Casing w/ Reducing Gear
Cooling Tower (existing)	Wet, Mechanical Draft

Flue Gas Flow Characteristics

Final Tube Bundle (LTVB) Outlet		
Temperature	(F)	746
Excess Air Level	(%)	20.0
Air Heater Outlet		
Temperature	(F)	321
Excess Air Level (equivalent)	(%)	31.8
Volumetric Flow	(ACFM)	165,000
NID Outlet		
Temperature	(F)	144
Volumetric Flow	(ACFM)	147,500

Material Flow Rates

Coal	(ton/hr)	19.91
Lime	(lb/hr)	4,608
FGD Waste Solids	(lb/hr)	11,930
Bottom Ash (dry)	(lb/hr)	666
Makeup River Water	(gpd)	965,000
Wastewater Discharge	(gpd)	363,000

TABLE 2
DESIGN-VALUE AMBIENT EMISSION RATES

Airborne

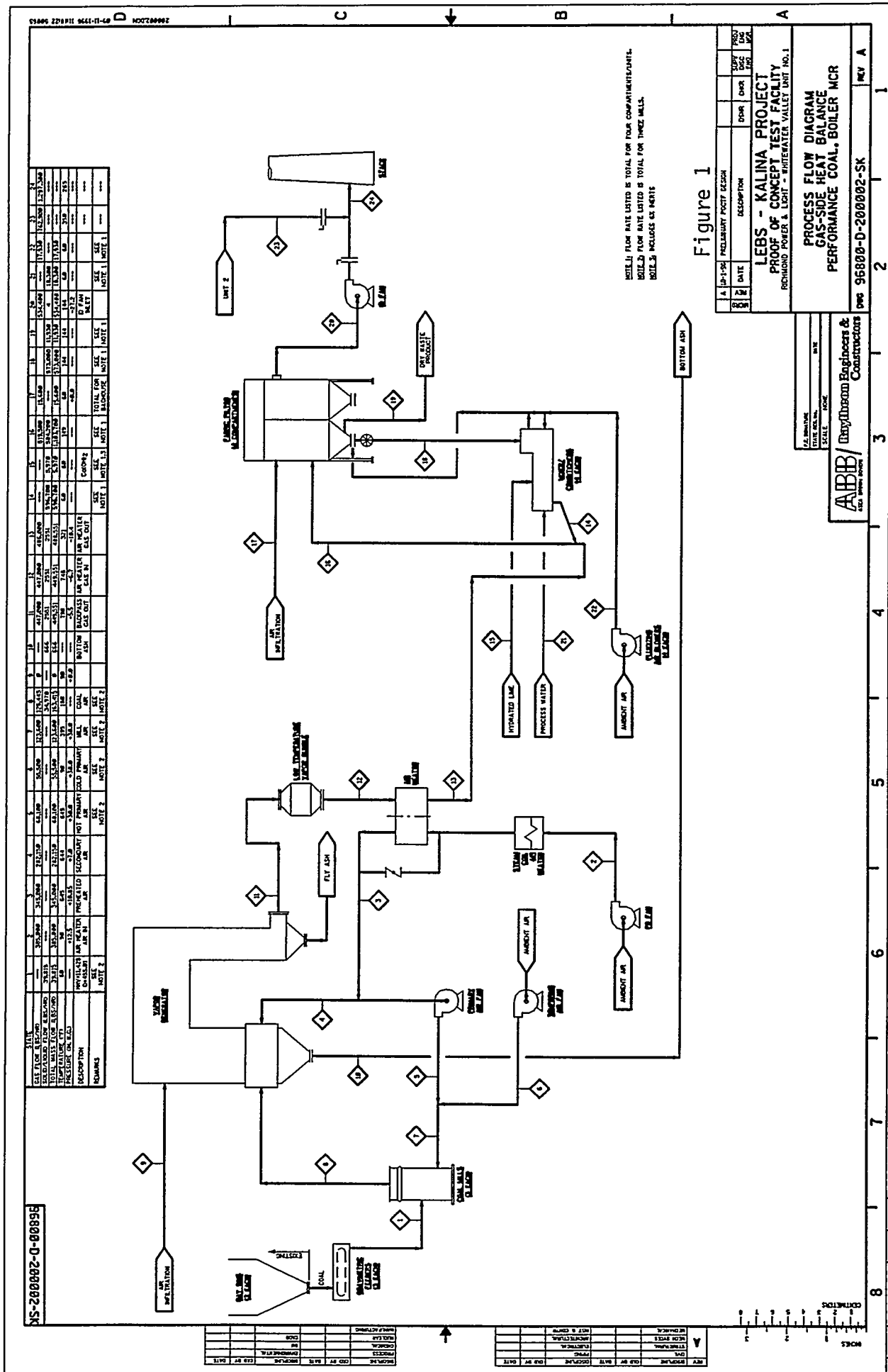
SO ₂ (98.3% Removal)	(lb/MMBtu)	0.1-0.2
NO _x	(lb/MMBtu)	0.1-0.2
Particulates	(lb/MMBtu)	0.01-0.005

Waste Solids (Ash + FGD)

Mass Rate	(ton/hr)	6.30
Specific Rate	(lb/kWh)	0.266

Water Discharge

Volume Rate	(gpd)	363,000
Specific Rate	(gal/kWh)	0.319



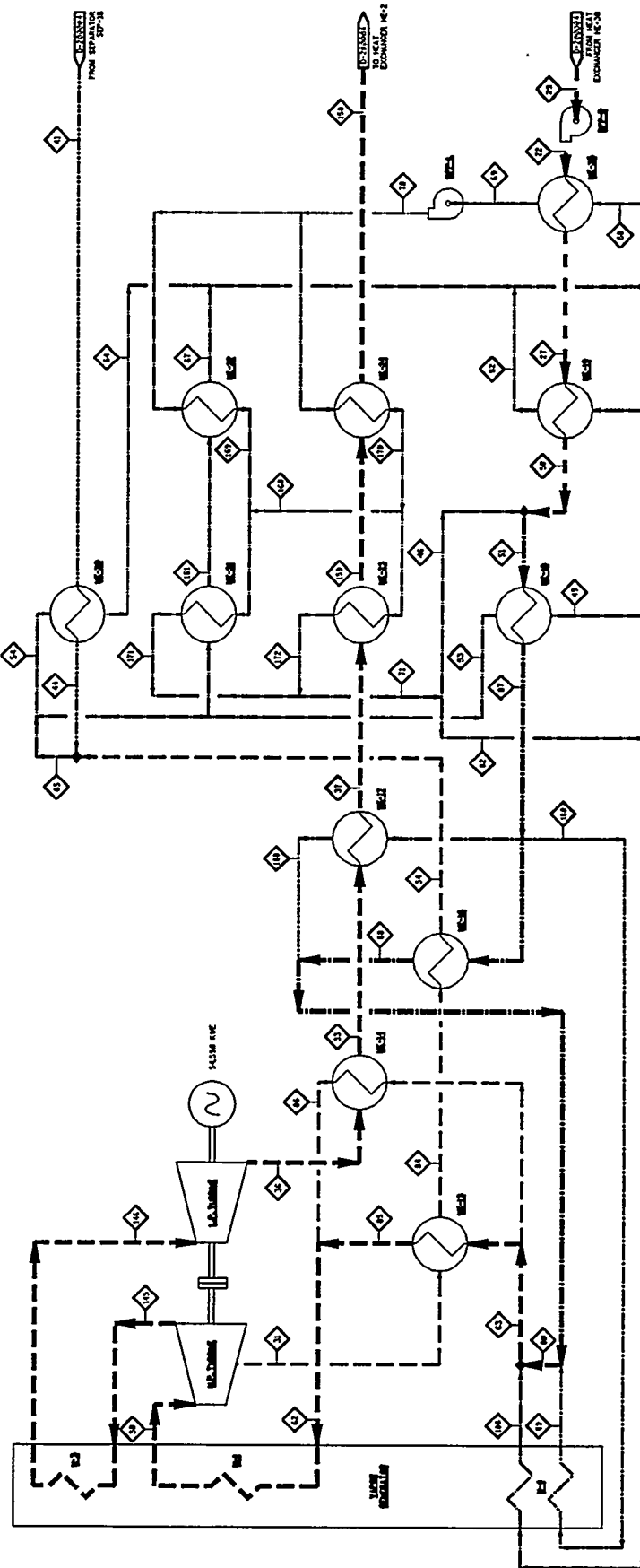
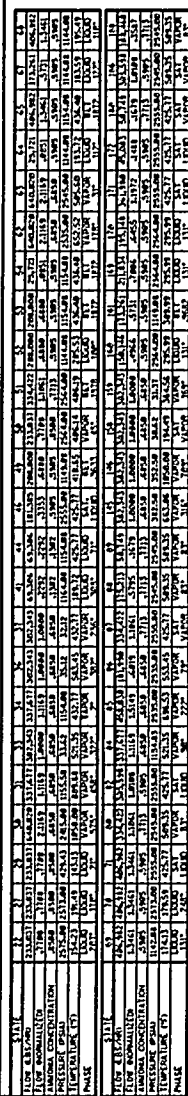


Figure 2A

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SCALE: NONE	

ABB / Daytheon Engineers & Constructors
 4524 BIRCH RD NW
 ALBUQUERQUE, NM 87109

Concentration	Unit Cost
0	20
.25	10
.7713	0
1.25	0
1.995	0
2.795	0
3.592	0

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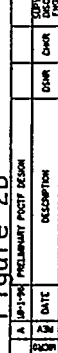


Figure 2B

LEBS - KALINA PROJECT
PROOF OF CONCEPT TEST FACILITY

**TURBINE HEAT BALANCE DIAGRAM
SHEET 2 OF 2
DISTILLATION /CONDENSATION SUBSYS**

96800-D-200004-SK

ABB
A.B.B. BROWN BOOTH
Baytheon Engineers & Constructors

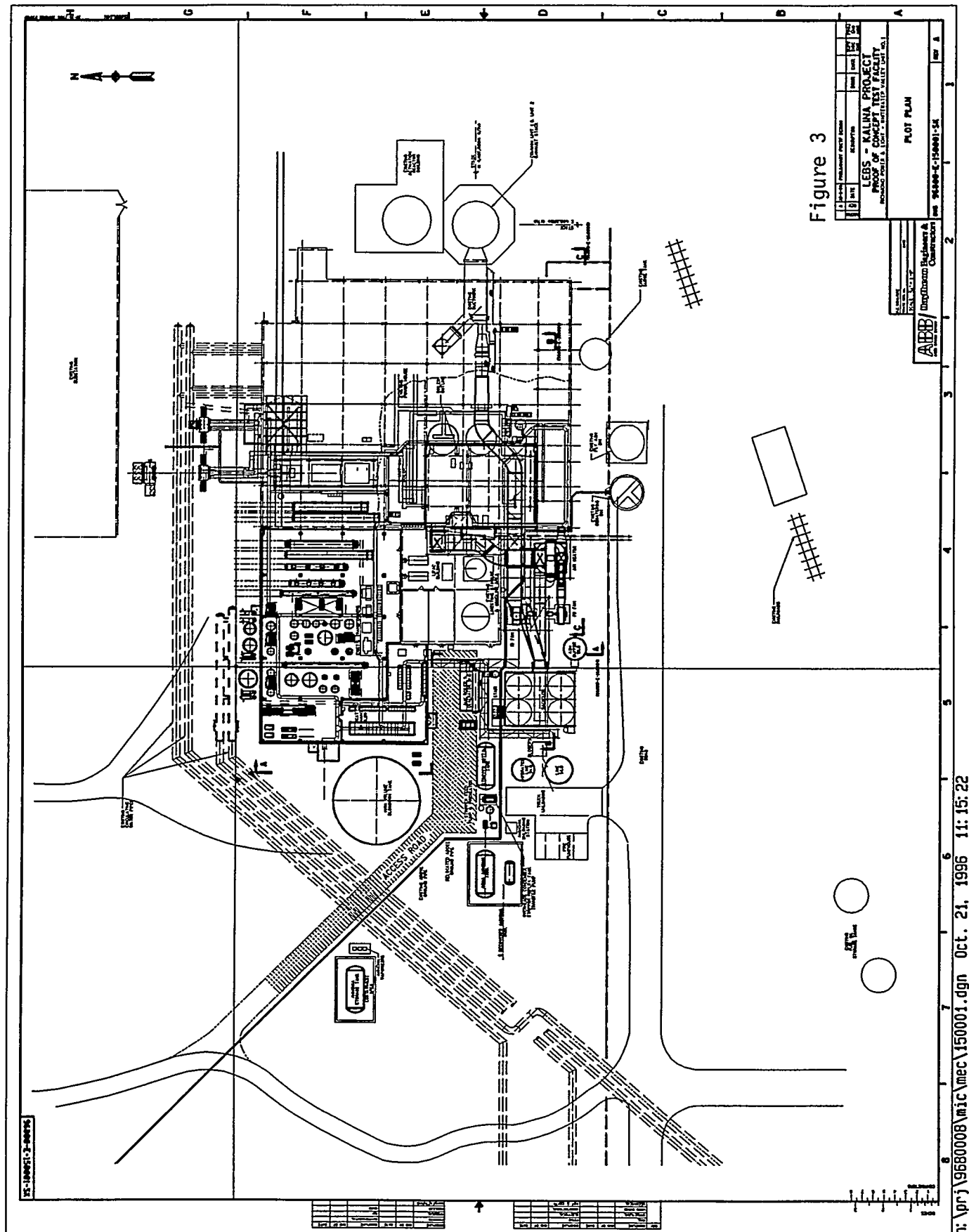
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ABB / Raytheon Engineers & Constructors

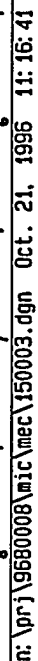
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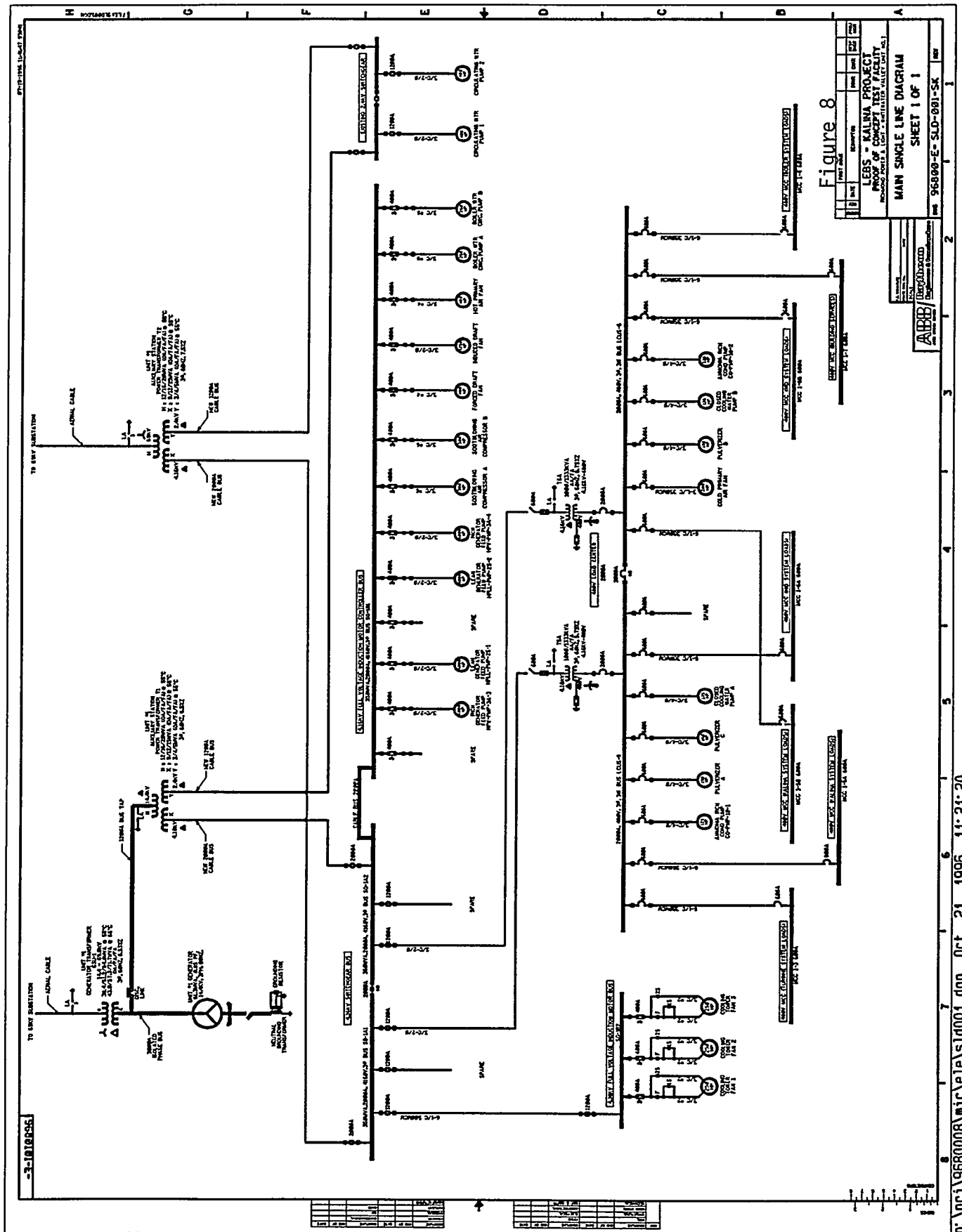
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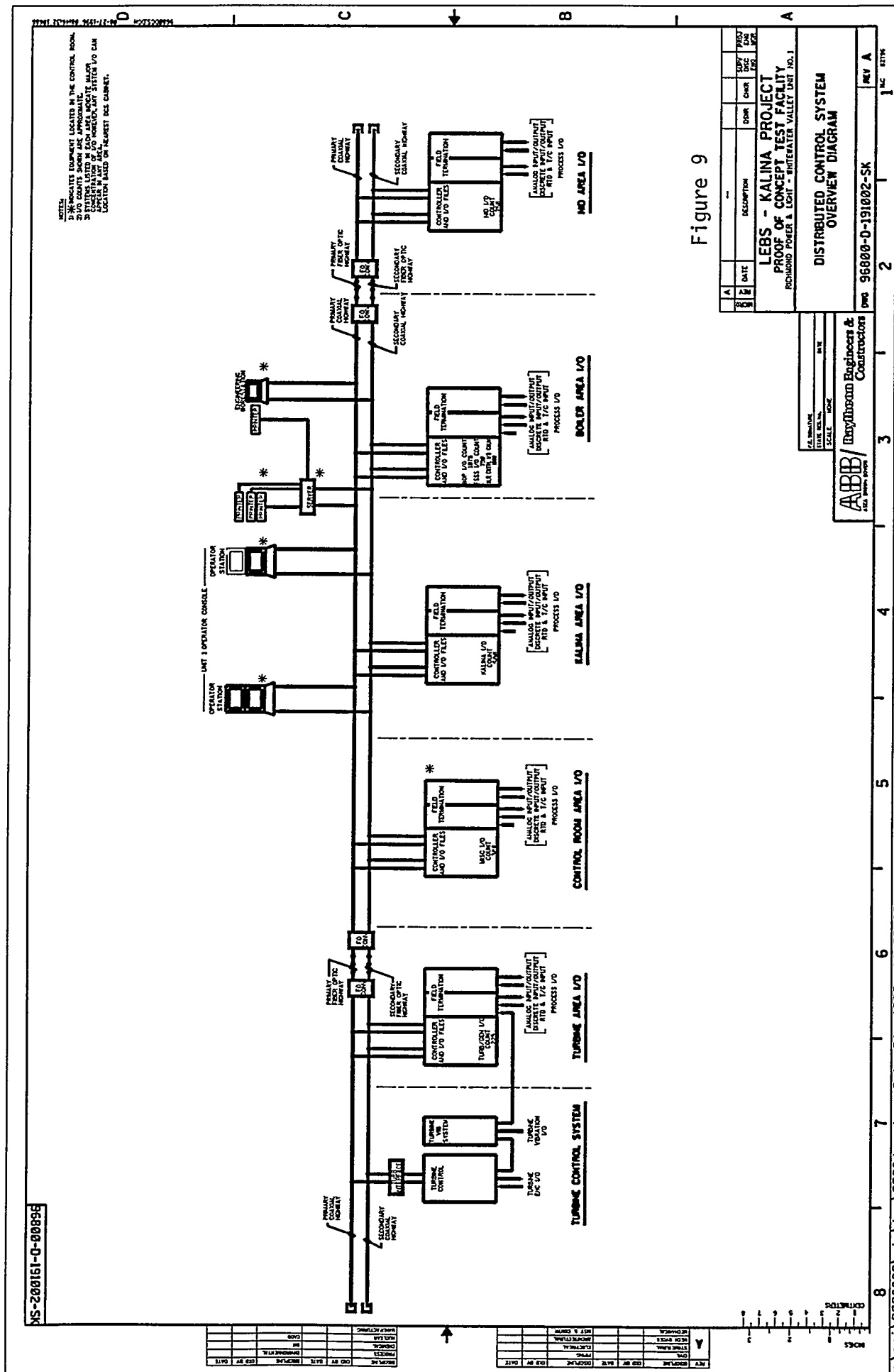
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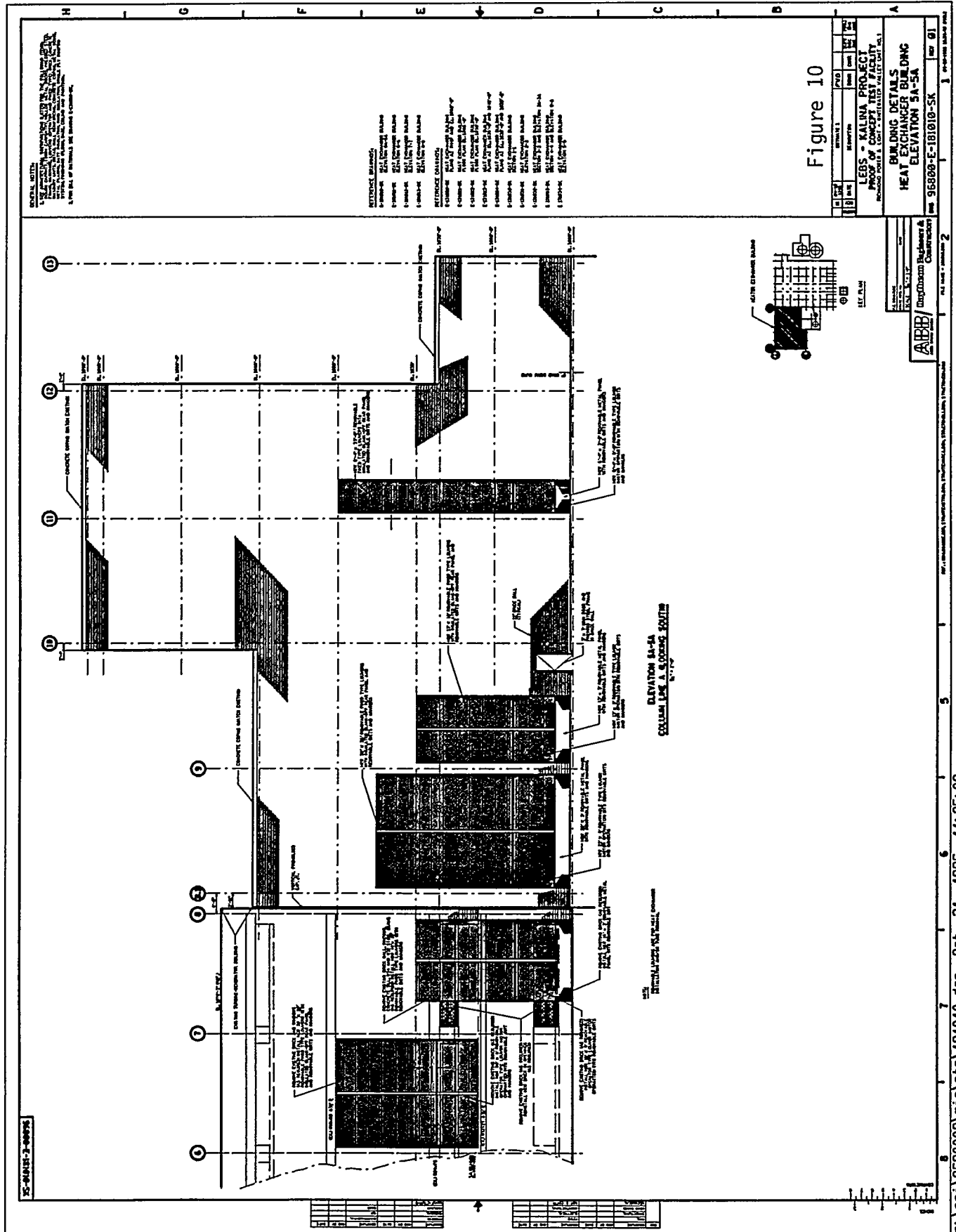



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TASK 9 - SUBSYSTEM TEST DESIGN AND PLAN

SNO_x Hot Process

Completed.

Low-NO_x Firing System

Completed.

TASK 10 - SUBSYSTEM TEST UNIT CONSTRUCTION

SNO_x Hot Process

The test rig for the 5,000 acfm test was returned to CeraMem. (NOTE: No LEBS funds were expended on this test rig.)

Low-NO_x Firing System

Completed.

TASK 11 - SUBSYSTEM TEST OPERATION AND EVALUATION

SNO_x Hot Process

Due to the unresolved issue of excessively high flue gas draft loss across the catalytic CeraMem filter and the projected inability to resolve it within the POCTF timeframe, further testing of the filter under LEBS was deleted, although it is recognized that the filter still has the potential to be commercially viable in pulverized coal fired systems.

Low-NO_x Firing System

Completed.

Reports

The following reports were issued in draft form, comments were received from DOE and were incorporated in the reports and the reports were issued in final form:

Subtask 11.2 - Subsystem Test Evaluation

Subtask 11.3 - Subsystem Design Evaluation

TASK 12 - PHASE II REPORT

Work continued on the Phase II Report which will be issued early in the next reporting period.

PLANS FOR NEXT QUARTER

Task 1

- Deliver a paper at the '96 International Joint Power Generation Conference.
- Chair a Combustion 2000 technical session at the '96 International Joint Power Generation Conference.

Task 8

- Complete and issue the report on the preliminary POCTF design.

Task 12

- Complete and issue the Phase II Report.

Phase III

- Initiate work on Tasks 13 and 14.

APPENDIX A - 2 pages

U.S. DEPARTMENT OF ENERGY
MILESTONE SCHEDULE ☐ PLAN ☒ STATUS REPORT

DOE F1332.3 X
(11-84)

1. TITLE Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems - Phases II & III		2. REPORTING PERIOD October 1, 1994 - SEPT 30, 1996												3. IDENTIFICATION NUMBER DE-AC22-92PC92159	
4. PARTICIPANT NAME AND ADDRESS Combustion Engineering, Inc. P.O. Box 500 Windsor, CT 06095-0500		5. START DATE October 1, 1994												6. COMPLETION DATE March 31, 1997	
7. ELEMENT CODE	8. REPORTING ELEMENT	9. DURATION												10. PERCENT COMPLETE	
		FY95												a. Plan	b. Actual
		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT		
1.0	PHASE II	[REDACTED]												80	80
7.0	Prj Mgt	[REDACTED]												100	100
8.0	Comp Dev	[REDACTED]													
	POCTF	[REDACTED]													
8.1	Site Sel	[REDACTED]												100	100
8.2	Pre Dsn	[REDACTED]												100	100
9.0	Subsyst	[REDACTED]													
9.1	Design	[REDACTED]												100	100
9.2	Plan	[REDACTED]												100	100
10.0	Constr	[REDACTED]												100	100
11.0	Subsyst	[REDACTED]													
11.1	Oper	[REDACTED]												100	100
11.2	Test Ev	[REDACTED]												100	100
11.3	Dsn Ev	[REDACTED]												100	100
12.0	Draft Report	[REDACTED]												100	88
11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE															
John W. Hagan Oct. 10, 1996															

APPENDIX B - 12 Pages

ABB'S LEBS ACTIVITIES - A STATUS REPORT

FIRST JOINT POWER
FUEL SYSTEMS
CONTRACTORS CONFERENCE

JOHN W. REGAN
ROBERT J. vonHEIN
ABB POWER PLANT LABORATORIES

LAWRENCE J. PELETZ, JR.
ABB CE UTILITY POWER BOILERS

JAMES D. WESNOR
ABB ENVIRONMENTAL SYSTEMS

DAVID J. BENDER
RAYTHEON ENGINEERS & CONSTRUCTORS

CONTRACT NO. DE-AC22-92PC92159

ABSTRACT

ABB Combustion Engineering, Inc. is one of three contractors executing Phases I, II and III of the Department of Energy project entitled Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems (LEBS). Phase I has been completed and Phase II is scheduled for completion on September 30, 1996. The following major activities are being carried out in parallel in Phase II and this paper is a status report on this work:

- In-furnace NO_x reduction
- Catalytic filter optimization
- Add Kalina cycle to POCTF
- POCTF design and licensing

The in-furnace NO_x reduction work has been completed and, therefore, a description of this work comprises the major part of this paper.

INTRODUCTION

The primary objectives of the LEBS project are, using near-term technologies, to dramatically improve environmental performance of future coal-fired power plants while increasing their efficiency and maintaining the cost of electricity at or below current levels. The secondary objectives are to improve ash disposability, reduce waste generation and reduce air toxics emissions. The overall objective is expedited commercialization of the technologies developed. The major deliverables are a design data base and the preliminary design of a commercial generating unit (CGU).

Since the award of contracts in September 1992 the DOE has asked the contractors to strive for ever lower emissions and higher efficiency. In addition ABB, with the addition of the Kalina cycle, has set an even higher efficiency target. Today the targets are as follows:

		<u>DOE Minimum Performance</u>	<u>DOE Preferred Performance</u>	<u>ABB's Targeted Performance</u>
SO ₂ *	lb/MM Btu	0.2	0.1	0.1
NO _x	lb/MM Btu	0.2	0.1	0.1
Particulates	lb/MM Btu	0.015	0.01	0.005
Efficiency (HHV, net), %		42	42	45

*3 lb S/MM Btu in the coal

Phase I consisted of selection of candidate technologies, creation of a preliminary 400 MWe CGU design and preparation of an RD&T Plan for Phases II and III. The Phase II work consists of: Component Optimization, POCTF Preliminary Design and Subsystem Testing. The four major Phase II activities are listed above in the ABSTRACT and are described below. (The work on in-furnace NO_x reduction is the only one completed.)

IN-FURNACE NO_x REDUCTION

Introduction: The most cost-effective method of reducing nitrogen oxide emissions when burning fossil fuels, such as coal, is through in-furnace NO_x reduction processes. For the LEBS project, the DOE has specified the use of near-term technologies to provide for these overall emissions reductions. Based on technical and economic feasibility, advanced tangential firing was selected as the primary means of NO_x emissions control for the ABB LEBS boiler design [1,2]. Specifically, ABB CE's TFS 2000™ firing system, which is a proven technology and commercially available, represents the technology selected as the basis for in-furnace NO_x reduction. This firing system design has been demonstrated to provide NO_x emissions of 0.2 pounds/MM Btu in prior laboratory and full scale, retrofit, utility boiler applications [3,4]. The objective of recent development work was to reduce this value to 0.1 lb/MM Btu.

Briefly, the TFS 2000™ firing system has been developed for minimum NO_x emissions from pulverized coal fired boilers, accomplished by way of combustion techniques only. Specific features of this system include the use of concentric firing system (CFS) air nozzles, where the main windbox secondary air jets are introduced at a larger firing circle than the fuel jets; close-coupled overfire air (CCOFA) for improved carbon burnout; and multi-staged separated overfire air (SOFA) to provide for complete combustion while maintaining an optimum global stoichiometry history for NO_x control. In addition, the TFS 2000™ firing system includes flame attachment coal nozzle tips for rapid fuel ignition and a pulverizer configured with a DYNAMIC™ Classifier to produce fine coal to minimize carbon losses under these staged combustion conditions.

Potential enhancements to the TFS 2000™ firing system focused on optimizing the introduction of the air and fuel within the primary windbox zone to provide additional horizontal and vertical staging. These enhancements were based on controlling the combustion of the coal in a more local sub-stoichiometric environment. That is, in addition to the global staging currently applied, improved NO_x reduction was sought by controlling and optimizing the mixing of the fuel and air locally through vertical and horizontal staging techniques. As is the case with all in-furnace NO_x control processes, it is necessary to operate the system in a manner which does not decrease NO_x at the expense of reduced combustion efficiency. The objective of recent developmental work on the firing system was to reduce NO_x emissions levels leaving the boiler to 0.1 pounds NO_x/MM Btu while maintaining carbon in ash at acceptably low levels (<5%) for high sulfur, mid-western and eastern bituminous coals.

The approach used in the development and evaluation of the various firing system concepts included an integrated approach of kinetic and computational modeling, small scale experimental testing in a Fundamental Scale Burner Facility (FSBF), and larger scale combustion testing in a Boiler Simulation Facility (BSF). Both modeling and experimental testing were applied to better understand the mechanisms governing in-furnace NO_x reduction and to identify potential enhancements to the TFS 2000™ firing system. Results from this testing were used in the development of advanced low NO_x firing systems which were evaluated in pilot scale combustion testing [5]. The pilot scale testing and evaluation of various advanced low NO_x firing systems is described below.

Pilot Scale Combustion Testing: Pilot scale combustion testing of in-furnace NO_x control systems was performed in ABB Power Plant Laboratories' BSF. The objective of this testing was to evaluate enhancements to the existing NO_x control technologies for improved NO_x emissions performance, while providing the necessary information for supporting the design of the NO_x control subsystem for the LEBS Proof-of-Concept Test Facility (POCTF).

The BSF is a pilot scale test furnace, nominally rated at 50 MM Btu/hour (5 MWe) for coal firing, that reliably duplicates the combustion characteristics of a tangentially-fired utility boiler. All major aspects of a typical tangentially-fired utility boiler are duplicated in the BSF including a v-shaped hopper for bottom ash collection, the

use of multiple burner elevations, and an arch with subsequent backpass convective "superheat," "reheat," and "economizer" surfaces. Selective refractory lining over atmospheric pressure "waterwalls" allows the matching of the residence time/temperature history of large scale utility boilers, including the horizontal furnace outlet plane (HFOP) gas temperature.

The BSF is fully instrumented to monitor the combustion process. Instruments for measuring coal feed rate, primary and individual secondary air mass flow rates, outlet emissions (O_2 , CO_2 , CO , SO_2 , NO , and NO_x), and convective pass heat flux distribution are tied into a combined DCS/data acquisition system to allow for control and logging of these and other important operational parameters. For the subject testing, the BSF was operated in a tangentially-fired mode with levels of separated overfire air (SOFA). Prior laboratory test programs have shown that BSF test results can be reliably translated to the field for use in firing system design, and subsequent performance prediction [3].

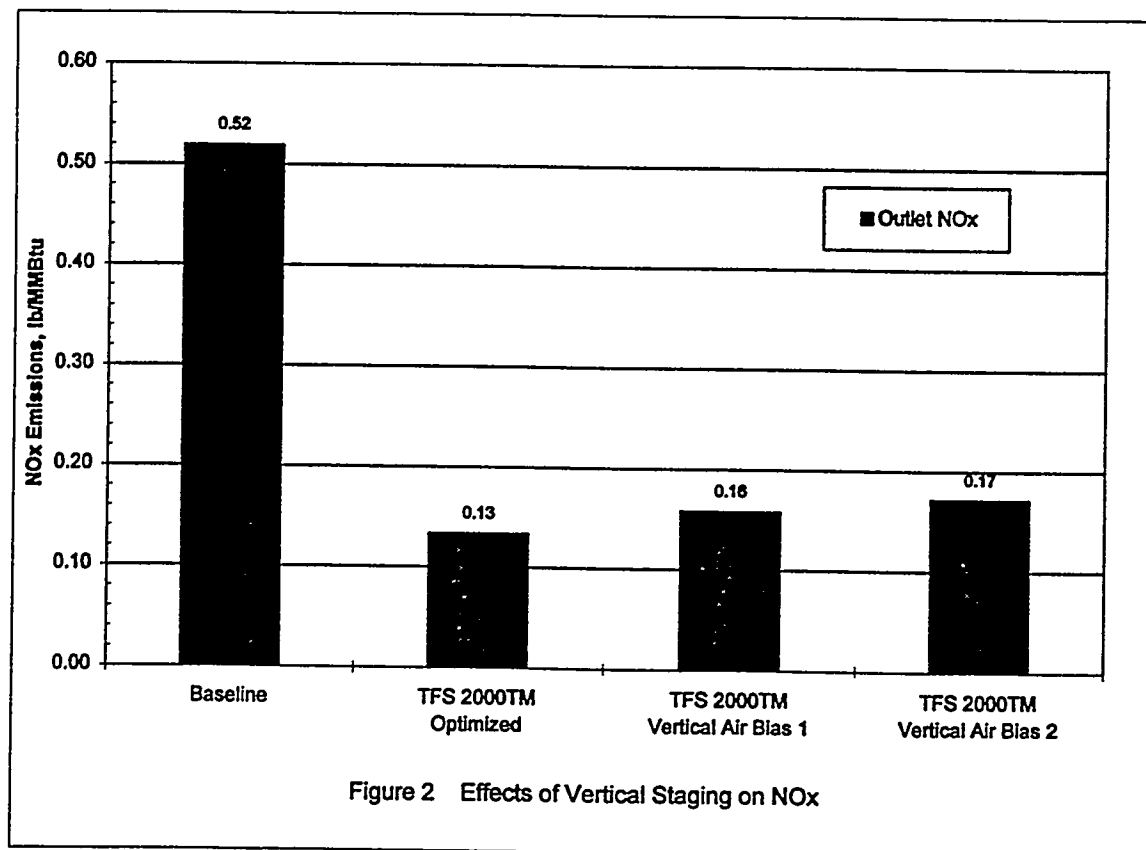
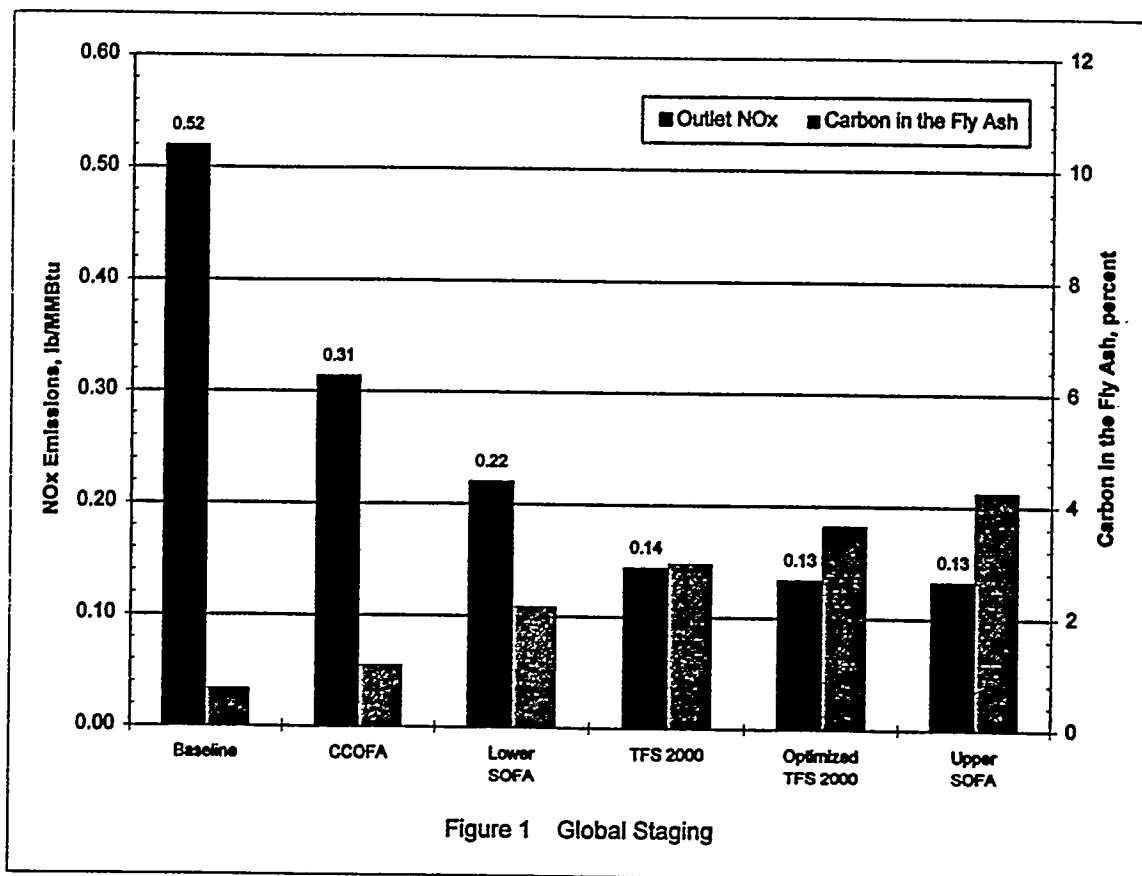
Performance targets for the BSF combustion testing were consistent with those for the LEBS program; maximum NO_x emissions of 0.1 pounds/MM Btu and carbon in the fly ash <5% for high sulfur, mid-western and eastern bituminous coals. In addition, the lower furnace heat absorption profiles and convective pass heat flux distribution were to remain similar to or improved over the existing system. The coal utilized during the BSF testing was the high sulfur, medium volatile, bituminous Viking coal from Montgomery, Indiana.

Prior to the initiation of NO_x control subsystem testing, the firing system for the BSF was modified to take advantage of current and previous R&D project findings. First, ABB CE's Aerotip™ coal nozzle tip design was utilized as the base from which the BSF coal nozzles were constructed. The Aerotip™ design embodies improved aerodynamic features which support the test program need for a low NO_x coal nozzle tip through its control over near field stoichiometry.

In addition to the incorporation of an Aerotip™ based coal nozzle tip, the main windboxes of the BSF were designed to accommodate a range of vertical and horizontal air and coal staging scenarios. The design of the secondary air nozzles was based on the need to maintain proper jet momenta, while having sufficient flexibility to test variations in vertical and horizontal air staging. In addition, excess coal nozzle capacity was incorporated to allow the testing of various coal staging scenarios, including two-corner coal firing. With this foundation, each of the "base" (*i.e.*, benchmark) firing system designs tested in the BSF, including the TFS 2000™ firing system, was able to incorporate the results of the prior chemical kinetic modeling and small scale (FSBF) combustion testing with respect to main windbox vertical air staging.

One goal of the BSF testing was to generate design data in support of achieving NO_x emissions of 0.1 pounds/MM Btu through in-furnace firing system modifications (*i.e.*, prior to any post combustion process NO_x reduction system). Toward this end, various "conventional" global air staging techniques were tested in order to benchmark their NO_x reduction potential on the test fuel. This work included investigations of close-coupled overfire air (CCOFA), upper and lower (single) elevations of separated overfire air (SOFA), and an implementation of TFS 2000™ technology. All of the various overfire air configurations utilized the same main windbox arrangement, and all were performed with high fineness (90% - 200 mesh) coal grind, which is consistent with TFS 2000™ firing system design standards.

A summary of the results from testing various overfire air configurations with the test coal are given in Figure 1. As anticipated, the implementation of global air staging results in a significant reduction in furnace outlet NO_x emissions. Beginning with NO_x emissions of 0.52 pounds/MM Btu with a typical "baseline" (post-NSPS) firing system arrangement, NO_x reductions continued to a low of 0.13 pounds/MM Btu for an "optimized" TFS 2000™ firing system arrangement (Note: similar 0.13 pounds/MM Btu outlet NO_x emissions were obtained with the upper SOFA only, but this was at slightly degraded carbon in the fly ash performance). The "optimized" TFS 2000™ system incorporates improvements to the bulk stoichiometry history over the initial TFS 2000™ test, with identical main and overfire air windbox configurations. In all, a 75% reduction in NO_x from baseline levels was achieved with the "optimized" TFS 2000™ system. As expected, carbon in the fly ash increased as the global staging was increased, but remained below the limit of 5%.



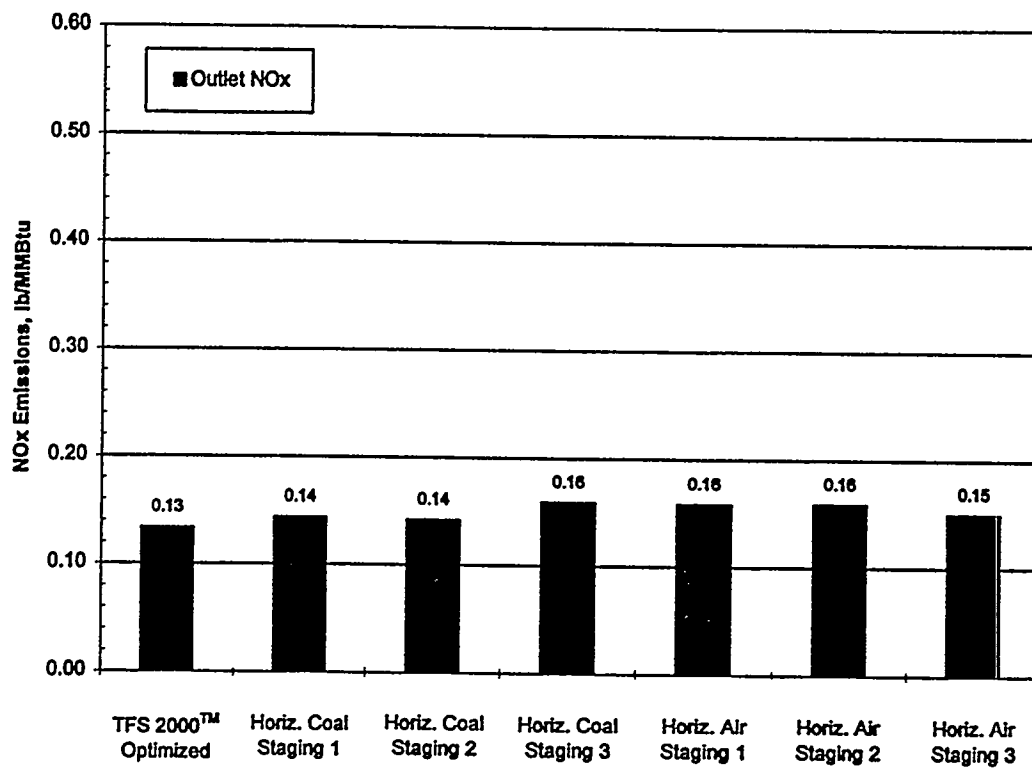


Figure 3 Effects of Horizontal Staging on NOx

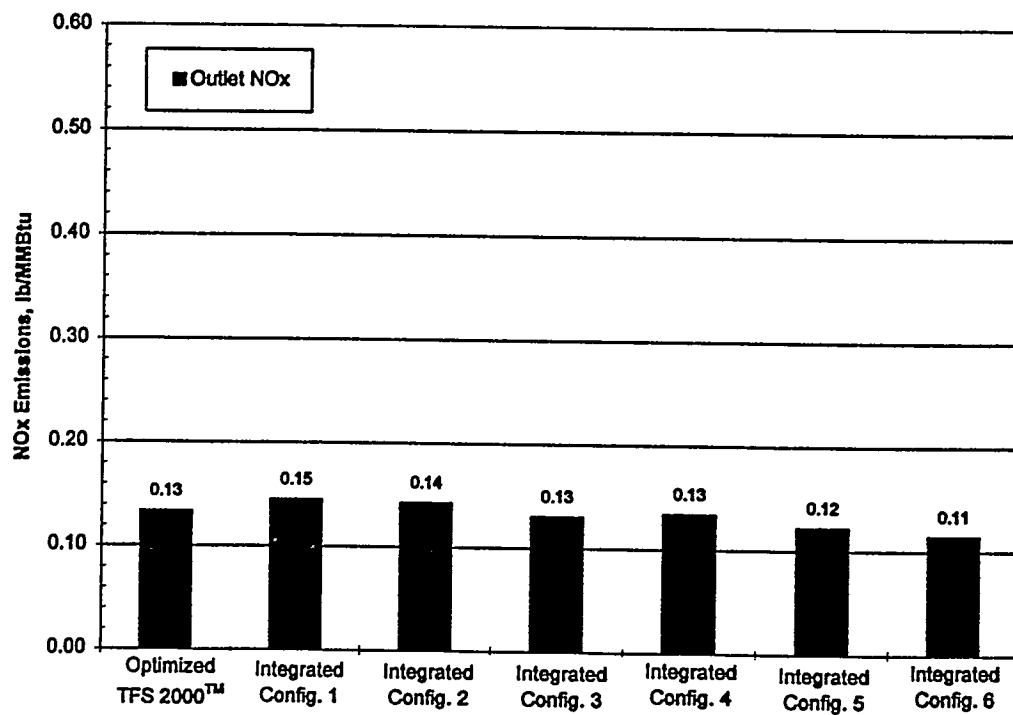


Figure 4 Effects of Integrated Staging on NOx

Having benchmarked the effects of global staging on firing system performance, both vertical and horizontal staging techniques within the main firing zone were subsequently tested to evaluate their effects on NO_x performance. The objectives of this work were to confirm the results of prior main windbox vertical air staging work, and to further reduce outlet NO_x emissions from the previously demonstrated "best" level of 0.13 pounds/MM Btu through the application of horizontal, and integrated vertical and horizontal main windbox staging techniques. As such, these methodologies were applied in concert with the "optimized" TFS 2000™ firing system, keeping the global stoichiometry history constant to allow meaningful comparisons.

First, vertical air staging within the main windbox was independently varied to demonstrate its effect on NO_x formation at this large pilot scale. Results from this testing, given in Figure 2, show that significant variation in NO_x emissions occur as main windbox vertical air staging is changed. In this case variations to the vertical air staging produced a +/- 13% deviation in outlet NO_x about the mean. This result confirms that the main windbox vertical stoichiometry history is an important contributor to overall NO_x formation, even with significant levels of global air staging. Overall, NO_x emissions increased when variations to the main windbox vertical stoichiometry build-up were applied to the previously "optimized" TFS 2000™ arrangement. This result is, however, expected since the "optimized" TFS 2000™ system incorporates the results of prior chemical kinetic modeling and small scale combustion test vertical air staging work into the configuration of its main windbox as noted above.

Next, horizontal staging, used to control the horizontal "build-up" of stoichiometry (corner to corner) within the main burner zone, was evaluated. This was accomplished by biasing the fuel and air between one or more of the four corners. Tested subsets of this technique are two corner firing, where all of the air and fuel are injected through two of four corners in a tangential arrangement, and opposed corner firing where the coal is injected from two corners, and the air from the remaining two. In general, independent implementation of horizontal staging techniques resulted in neutral to degraded NO_x emissions performance over that of the "optimized" TFS 2000™ firing system during the subject testing. This is seen in Figure 3, which shows the effect of independent variation of either fuel or air (horizontal staging) on overall NO_x emissions performance. These results demonstrate that, similar to the prior vertical staging experiments, outlet NO_x emissions can be affected by horizontal fuel and air distributions. However, these results also demonstrate that the global time - stoichiometry history (*i.e.*, the TFS 2000™ stoichiometry profile) dominates the NO_x formation and reduction processes at these levels of global air staging.

Finally, several configurations which applied integrated vertical and horizontal staging techniques as a means of "optimizing" the stoichiometry of combustion within the main windbox were evaluated. Integrated vertical and horizontally staged firing systems were extensively evaluated using CFD modeling prior to the BSF tests. In contrast to their independent performance, Figure 4 shows that when suitably combined, an integrated vertical and horizontal staging strategy offers a small, but consistent improvement to the NO_x emissions performance of the optimized TFS 2000™ system. At a NO_x emission level of 0.11 pounds/MM Btu, the "best" integrated system ("Integrated Config. 6") produced a greater than 10% reduction in NO_x over the previously "optimized" TFS 2000™ system. Carbon loss results (not shown) were also similar for the two firing systems.

Additional pilot scale testing of potential NO_x control subsystems in the BSF has been recently completed and results are being analyzed. The objective of this testing was to confirm the performance of the integrated vertical and horizontal staging technique, focusing on the repeatability of the present test results, while generating design information for this and other promising firing system concepts for eventual full scale utility boiler application.

CATALYTIC FILTER OPTIMIZATION

Introduction: The principal goal of the Catalytic Filter Optimization activities is the acquisition of initial field test data, which will be used for a larger field demonstration. These activities include the determination of feasible and reasonable operating conditions for the catalytic filter system. Data collected through testing will focus on particulate and NO_x removal efficiencies as well as filter draft loss.

The goals of this task are listed below in order of priority. It is desirable that these goals be achieved simultaneously.

- Particulate emissions of less than 0.005 lb/MMBtu
- Maximum filter clean-side draft loss of 8 inches w.g. at 4 ft/min at 775°F
- Operation with a Filter Face Velocity (FFV) of at least 4 ft/min at 650°F
- Minimum of 80% NO_x removal efficiency
- Ammonia slip of less than 15 ppm

Information gained from demonstration and evaluation will address the following issues:

- Confirm filter particulate removal efficiency.
- Determine the tubesheet differential pressure (filter draft loss) as a function of face velocity, cleaning cycle characteristics, operating time, and other parameters.
- Determine the NO_x reduction efficiency as a function of flue gas composition (NO_x inlet concentration, NH₃ stoichiometry, particulate removal), and flue gas temperature. Of further interest is the determination of the requirements to maintain the catalytic conversion efficiency.

Approach: The approach used is to test the Catalytic Filter System with four filter modules on a 100 ACFM (165 m³/hr) slipstream at Richmond Power & Light's Whitewater Valley Station Unit 2, a 66 MWe pulverized coal-fired boiler. CeraMem manufactured the ceramic filter modules and Engelhard applied the NO_x reduction catalyst.

A slipstream unit was constructed and installed at the Richmond site, taking flue gas off the boiler at the economizer section, processing the gas to remove particulate and NO_x, and returning the gas to the air heater. The test system was installed at the site February and March of this year, and operation started immediately upon completion of installation. At this writing, an initial 500-hour test has been concluded, in which both particulate removal and NO_x reduction were investigated.

Preliminary Results: *The tubesheet differential pressure* (filter draft loss) is considered an essential element to the success and applicability of the catalytic filter to the LEBS Commercial Generating Unit (CGU) design. An excessive tubesheet differential pressure would require excessive fan power to move the flue gas through the system for processing. For the first 500-hour test, the initial tubesheet differential pressure was approximately 16 inches w.g. (FFV=4 ft/min, T= 650°F).

The filter permeance, a parameter inversely proportional to tubesheet differential pressure and independent of filter face velocity and process temperature, decreased through the first 150 hours of operation, as shown in Figure 5. This decrease indicated that the filter tubesheet differential pressure increased at constant process conditions, an effect that is typical of all ceramic particulate filters. This decrease in permeance or increase in tubesheet differential pressure is caused by the smaller particulate (less than 0.5μ diameter) becoming permanently lodged in the filter substrate. For all ceramic particulate filters, the filter permeance should stabilize at some point, indicating that essentially the pores that are able to become "plugged" have been, and that the filter is being cleaned efficiently. At this point, the tubesheet differential pressure will remain constant at constant process conditions. In the case of the initial 500-hour test, the tubesheet differential pressure rose to approximately 23-24 inches w.g. (FFV=4, T=650°F) after approximately 200 hours of operation and was stable for the remainder of the test.

Upon conclusion of the 500-hour test, the system was opened and the filter modules were inspected. Visual inspection showed that the filters were being cleaned effectively, with no particulate buildup being detected and no plugged channels being found.

Subsequent analysis of the catalytic filters indicate that catalyst addition was responsible for approximately 75 % of the tubesheet differential pressure.

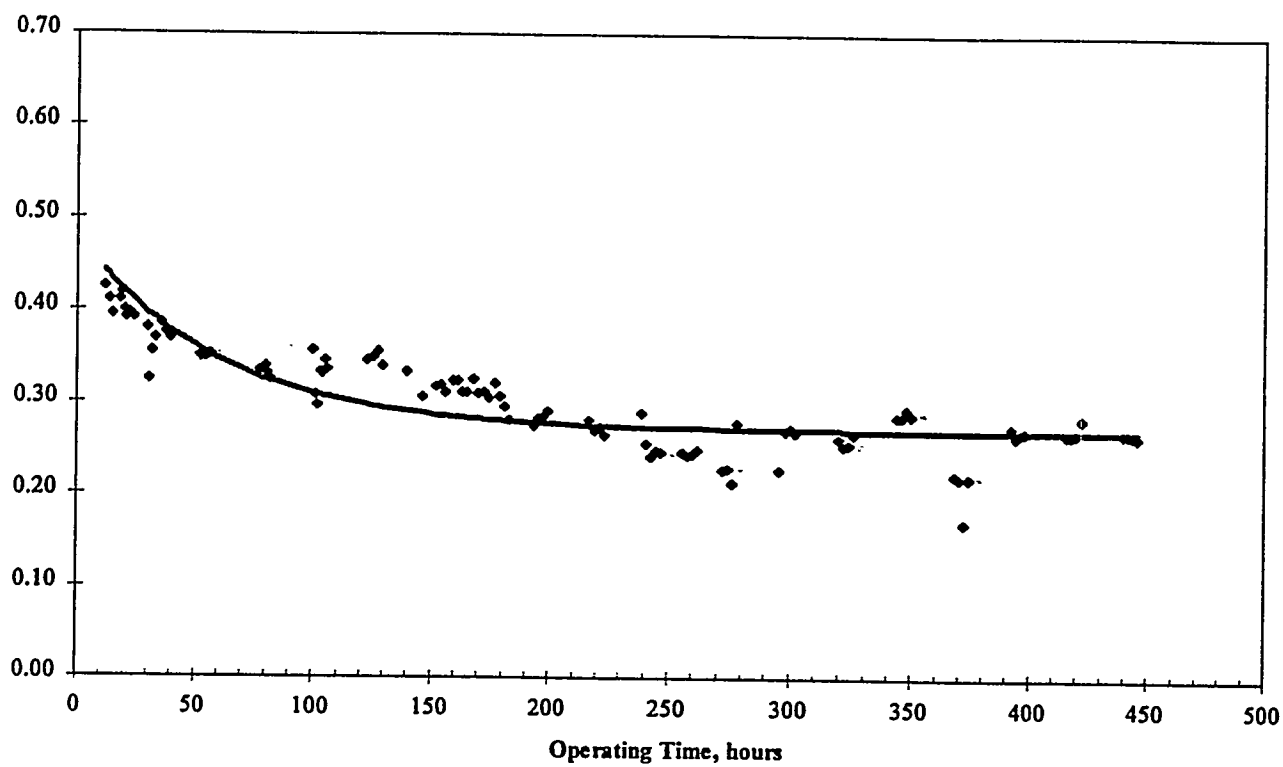


Figure 5 - Filter Permeance vs. Operating Time

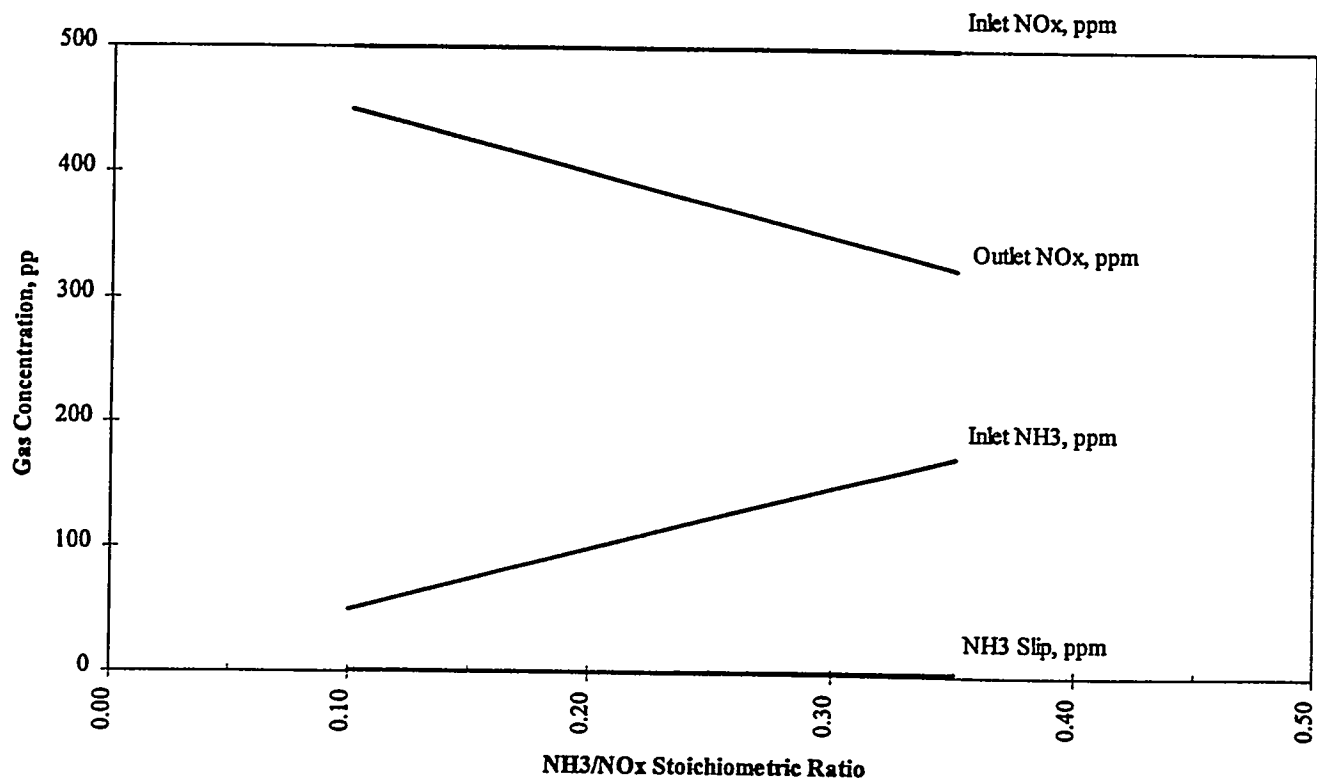


Figure 6 - NOx Reduction

Particulate removal for this filter system was expected to be near absolute. In previous testing of the filter system at ABB's corporate laboratory in Baden, Switzerland, outlet emissions from the filter could not be detected using a laser light-scattering measurement system, indicating that removal efficiency exceeded 99.99994%.

In the 500-hour test, two outlet particulate samples were taken, with results indicating a removal efficiency of 99.93% which is below the expected value.

Upon completion of the 500-hour test, the unit was opened and the tubesheet and vessel inspected. Lack of particulate matter on the "clean-side" of the tubesheet, particularly in cracks and crevices, tends to indicate that particulate matter was not passing through the filters and that the sampling results were reflective of material that had been left in the ducts when the system was being bypassed.

NO_x Reduction Efficiency testing was initiated after approximately 350 hours of operation. Ammonia was injected into the system to facilitate the NO_x reduction reaction. Inlet and outlet ammonia sampling was conducted to quantify ammonia injection rates and ammonia slip, while NO_x inlet and outlet concentrations were determined using two ThermoElectron Model 10 NO_x CEMs. Due to vendor problems that are beyond the scope of the paper, maximum injection stoichiometry was limited to 0.4 (maximum ammonia concentration in the inlet flue gas was approximately 200 ppm).

Preliminary results indicate that the catalyst made efficient use of the ammonia, as shown in Figure 6. The ammonia was fully accounted for in the NO_x reduction reaction, and sampling and analysis found less than 3 ppm in the outlet flue gas in all samples.

Future Tests: It is unlikely that an advancement in catalyst deposition technology will be made that will achieve an initial tubesheet pressure differential of less than 8 inches w.g. within the 100 ACFM Test time frame. A second 500-hour test is presently under way to gather engineering data on the performance of a non-catalytic filter system. Catalyst development is continuing in a parallel program, with the hope of being able to achieve project goals by completion of Phase II.

POCTF DESIGN AND LICENSING WITH A KALINA CYCLE

Introduction: The centerpiece of the LEBS project is Phase IV which will undertake the design, construction and test operation of a proof-of-concept test facility (POCTF). These final-phase activities will provide the design and operating database critical to commercialization of the LEBS technologies. The current project plans are that only one of the three original LEBS teams, with their respective technologies, will be selected to implement Phase IV. The on-going Phase II and III tasks, however, include the precursor planning activities leading up to down-selection and Phase IV initiation. At present, the ABB LEBS team is developing a site-specific preliminary design for their POCTF, and has project licensing in progress.

Project Description: ABB has been fortunate in obtaining a commitment for an outstanding host site for their POCTF. Richmond (Indiana) Power & Light Co. (RP&L) has offered to host the project at their Whitewater Valley station. RP&L has a history of successful involvement in technology demonstration programs, including one of the earliest low NO_x burner installations, a LIMB installation, and a Clean Coal Technology project.

The Whitewater Valley plant is composed of two coal-fired, non-reheat units, with nominal ratings of 33 MWe (unit 1) and 66 MWe (unit 2). Unit 1 will be modified to accept the LEBS technology package. This unit is approximately 40 years old, and incorporates a 900F/900 psig steam cycle with a steam capacity of 325,000 lb/hr. The POCTF project will involve a major restructuring of the unit, that entails the replacement of the complete power system (boiler, turbine-generator, feedwater heaters, power piping) with a new Kalina-based power system, and addition of the LEBS flue gas cleanup system. The project will use the plant infrastructure to the maximum extent practical, including coal handling, heat rejection, ash handling, powerhouse structures, and auxiliary systems. Although the project is being implemented as a test facility, RP&L intends to use the unit for long-term

production service following completion of the LEBS project. This criterion, therefore, has a dominant effect on specification and design of the equipment and the facility.

The approach taken in establishing the size of the modified unit has been to maximize its generating capacity, consistent with making maximum use of existing plant infrastructure. Key plant performance parameters are summarized in Table I.

Table I - UNIT 1 PERFORMANCE PARAMETERS
(Preliminary)

<u>Thermal</u>		<u>Existing</u>	<u>POCTF</u>	<u>Change</u>
Coal Heat Input	MM Btu/hr	400	440	+ 10%
Cooling Tower Load	MM Btu/hr	216	215	
Generator Output	MWe	35.6	54.6	
Auxiliary Load	MWe	2.2	6.7	
Net Unit Generation	MWe	33.4	47.9	+ 43%
Net Unit Heat Rate	Btu/kWh	12,000	9,186	- 23%
<u>Environmental</u>				
SO ₂	lb/MM Btu	6.0 / 1.6 ^(*)	0.1 to 0.2	/ - 90%
NO _x	lb/MM Btu	- / 0.5 ^(*)	0.1 to 0.2	/ - 70%
Particulates	lb/MM Btu	0.19 / 0.19 ^(*)	0.01	/ - 95%

(*) pre/post Phase II Clean Air Act Amendments (2000)

By leveraging the significant improvement in heat rate offered by the Kalina cycle with a modest 10% increase in coal heat input, the unit output will be increased a substantial 43% to about 48 MWe, with a corresponding 23% decrease in heat rate. At the projected net unit heat rate of about 9,200 Btu/kWh, the modified Whitewater Valley unit 1 will be the most efficient coal-fired unit of its size in the U.S. The planned project, in fact, compares favorably to the best coal-fired unit heat rate reported in the USA in 1994 of 8,889 Btu/kWh (annual average) for a 660 MW supercritical unit.

Equipment: To date, an initial feasibility study for the project has been completed, and the preliminary design is in progress. Highlights of this on-going project conceptualization are described below.

Because the Kalina cycle optimizes at different thermodynamic conditions than a steam cycle, and because of the change in working fluid and the increase in generating capacity, the complete steam side of the power cycle is to be removed and replaced. These systems include the boiler and auxiliaries, turbine-generator and auxiliaries, condenser, condensate system and feedwater system. The size of the unit has been selected such that the new vapor generator will fit in the existing boiler support-steel cavity, and the new turbine-generator will fit the existing turbine pedestal (after pedestal modification). The fact that the Kalina cycle regenerates substantially more heat than a steam cycle results in a significant increase in the number of regenerative heaters, such that a turbine hall addition will be required to house this new equipment.

The vapor generator, or boiler, design for the POCTF is a single reheat, drum type with pumped circulation for cooling furnace wall evaporative tubes. The Kalina cycle, with its higher rate of heat regeneration, requires less evaporation but more superheater and reheater duty in the vapor generator. Thus, in addition to pendant and horizontal superheater and reheater surfaces, in the preliminary design portions of the upper furnace walls are used for superheating and reheating the working fluid. The design of these sections is the same as conventional radiant wall reheater designs. The vapor generator looks very much like a large utility unit designed for a Rankine cycle.

Turbine design performance for a Rankine or Kalina cycle is very similar. Ammonia has a molecular weight very close to that of pure water, (17 vs. 18). This allows the use of current designs for turbine blading and turbine shell to be used in a Kalina cycle. One major difference in the turbine, when used in a Kalina cycle, is that the turbine is changed to a back pressure configuration. In doing so, there is no need for the large low pressure section and vacuum system which are required in the Rankine cycle. This provides a capital cost saving as well as improved system efficiency.

In addition, the inclusion of the LEBS flue gas emissions control features dictates removal of the gas side power cycle systems. The replacement systems will include the low NO_x firing technology described previously, a new draft system, and a flue gas cleanup system. At present, two alternative processes are being evaluated for flue gas cleanup: the SNO_xTM hot process and an advanced dry-scrubbing process.

Control requirements associated with the Kalina power cycle, and the fact that unit 1 still has its original control system, dictate that the project will include installation of a new unit-wide distributed control system. The increase in auxiliary power consumption associated with the modified unit also requires that the station service transformers for unit 1 (unit auxiliary and startup) be replaced with larger capacity units, and substantial new power distribution capability be added.

Licensing: A licensing plan and schedule have been developed for the project that has identified the need to obtain twelve individual environmental/safety permits and approvals. As indicated in Table I, the project will result in large reductions of all the regulated air emissions from unit 1. Thus, approvals for the air permits are expected to be relatively straight forward. Unique to this power project, however, is the significant ammonia inventory required for operation of the Kalina cycle. The presence of this material on site will require the development of plans to deal with a potential accidental ammonia release.

The licensing schedule is based on obtaining all approvals prior to the planned start date for Phase IV. At present, contact has been established with the Indiana Department of Environmental Management (IDEM). IDEM has been thoroughly briefed on the proposed project, and preparation of the long-lead permit applications is in progress.

CONCLUSIONS AND FUTURE WORK

Testing of the low-NO_x firing system has been completed. The work remaining is analysis of data from the second week of testing in the BSF. The NO_x emission target of 0.1 lb/MM Btu with <5% carbon in the fly ash was achieved in the BSF (actually 0.11 lb). However, at this time it cannot be predicted with certainty that 0.1 lb/MM Btu will be achieved in commercial size systems. There presently is no further LEBS firing system development work planned prior to construction of the POCTF.

The preliminary results of the catalytic filter field testing were very encouraging regarding particulate emissions and NO_x reduction. However, measured gas draft loss was excessive. Since approximately 75% of the draft loss is attributed to the catalyst, testing will continue with a non-catalytic filter system while catalyst deposition technology is reviewed. Also, since it is possible that the catalytic filter draft loss situation may not be resolved within the POCTF schedule, an alternative technology will be evaluated.

The POCTF design work was rescheduled to allow time to design the Kalina cycle components and to integrate them into the existing facilities at the host site. That work is essentially complete and plant design and licensing work has resumed and will be completed within the project schedule.

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APPENDIX C - 8 pages

13TH ANNUAL INTERNATIONAL
PITTSBURGH COAL CONFERENCE
SEPT. 1996 - PITTSBURGH

THE ABB LEBS SYSTEM DESIGN

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ABSTRACT

The objectives of the U.S. Department of Energy (DOE) "Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems" (LEBS) project are to dramatically improve environmental performance of future pulverized coal-fired power plants, to increase their efficiency and to reduce their cost of electricity using near-term technologies, *i.e.*, advanced technologies that are partially developed. The overall objective is to expedite commercialization of the technologies that are developed. The paper describes the work by the ABB team on the LEBS project which is part of the DOE's Combustion 2000 Program.

A major deliverable of the Project is the design of a 400 MWe commercial generating unit (CGU). The design being developed by the ABB team is projected to meet all the project objectives and to reduce emissions of NO_x, SO₂ and particulates to one-third to one-sixth NSPS limits while increasing net station efficiency significantly and reducing the cost of electricity. Development activities supporting the design work are described in the paper.

INTRODUCTION

The LEBS performance objectives and the technologies selected to attain the objectives are summarized in Table 1. [1]

TABLE 1 - ABB's LEBS Performance Objectives and Technologies

	<u>Objective</u>	<u>Technology</u>
Emissions, lb/Million Btu		
NO _x	0.1	TFS 2000™
SO ₂ *	0.1	Hot SNO _x ™ or NID™
Particulates	0.01	Hot SNO _x ™ or NID™
Efficiency (Net Plant, HHV)	42%	Advanced Rankine Cycle
	or 45%	Kalina Cycle

*3 lb SO₂/Million Btu in the coal

All of the technologies listed in Table 1 meet the project definition of "near-term". The development work leading to commercial readiness of these technologies is described below. The recent major activities have been: (1) in-furnace NO_x reduction, (2) catalytic filter optimization and (3) proof-of-concept test facility (POCTF) design/licensing with a Kalina cycle.

IN-FURNACE NO_x REDUCTION

Introduction. ABB's TFS 2000™ firing system was selected in Phase I of the LEBS project. It has been demonstrated to provide NO_x emissions of 0.2 pounds/MM Btu in prior laboratory and full scale, retrofit, utility boiler applications. The objective of recent development work was to reduce this value to 0.1 lb/MM Btu while maintaining the fly ash carbon content <5% for high sulfur, mid-western and eastern bituminous coals. In addition, the lower furnace heat absorption profiles and convective pass

heat flux distribution were to remain similar to or improved over the existing system. Specific features of this system include the use of concentric firing system (CFS) air nozzles, where the main windbox secondary air jets are introduced at a larger firing circle than the fuel jets; close coupled overfire air (CCOFA) for improved carbon burnout; and multi-staged separated overfire air (SOFA) to provide for complete combustion while maintaining an optimum global stoichiometry history for NO_x control. In addition, the TFS 2000™ firing system includes flame attachment coal nozzle tips for rapid fuel ignition and a pulverizer configured with a DYNAMIC™ Classifier to produce fine coal to minimize carbon losses under these staged combustion conditions.

Potential enhancements to the TFS 2000™ firing system focused on optimizing the introduction of the air and fuel within the primary windbox zone to provide additional horizontal and vertical staging. These enhancements were based on controlling the combustion of the coal in a more local sub-stoichiometric environment. That is, in addition to the global staging currently applied, improved NO_x reduction was sought by controlling and optimizing the mixing of the fuel and air locally through vertical and horizontal staging techniques. The approach used in the development and evaluation of the various firing system concepts included an integrated approach of kinetic and computational modeling, small scale experimental testing in a Fundamental Scale Burner Facility (FSBF), and larger scale combustion testing in a Boiler Simulation Facility (BSF). These techniques were applied to better understand the mechanisms governing in-furnace NO_x reduction and to identify potential enhancements to the TFS 2000™ firing system.

Pilot Scale Combustion Testing. The BSF is a pilot scale test furnace, nominally rated at 50 MM Btu/hour (5 MWe) for coal firing, that reliably duplicates the combustion characteristics of a tangentially-fired utility boiler. All major aspects of a typical tangentially-fired utility boiler are duplicated in the BSF including a v-shaped hopper for bottom ash collection, the use of multiple burner elevations, and an arch with subsequent backpass convective "superheat," "reheat," and "economizer" surfaces. Selective refractory lining over atmospheric pressure "waterwalls" allows the matching of the residence time/temperature history of large scale utility boilers, including the horizontal furnace outlet plane (HFOP) gas temperature. The BSF is fully instrumented to monitor the combustion process. Instruments for measuring coal feed rate, primary and individual secondary air mass flow rates, outlet emissions (O₂, CO₂, CO, SO₂, NO, and NO_x), and convective pass heat flux distribution are tied into a combined DCS/data acquisition system to allow for control and logging of these and other important operational parameters. The coal utilized was the high sulfur, medium volatile, bituminous Viking coal from Montgomery, Indiana.

Prior to the initiation of NO_x control subsystem testing, the firing system for the BSF was modified to take advantage of current and previous R&D project findings. First, ABB's Aerotip™ coal nozzle tip design was utilized as the base from which the BSF coal nozzles were constructed. The Aerotip™ design embodies improved aerodynamic features which support the test program need for a low NO_x coal nozzle tip through its control over near field stoichiometry. In addition, the main windboxes were designed to accommodate a range of vertical and horizontal air and coal staging scenarios. The design of the secondary air nozzles was based on the need to maintain proper jet momenta, while having sufficient flexibility to test variations in vertical and horizontal air staging. Excess coal nozzle capacity was incorporated to allow the testing of various coal staging scenarios, including two-corner coal firing. With this foundation, each of the "base" (i.e., benchmark) firing system designs tested, including the TFS 2000™ firing system, was able to incorporate the results of the prior chemical kinetic modeling and small scale (FSBF) combustion testing with respect to main windbox vertical air staging.

Various "conventional" global air staging techniques were tested in order to benchmark their NO_x reduction potential on the test fuel. This work included investigations of close coupled overfire air (CCOFA), upper and lower (single) elevations of separated overfire air (SOFA), and an implementation of TFS 2000™ technology. All of the various overfire air configurations utilized the same main windbox arrangement, and all were performed with high fineness (90% - 200 mesh) coal grind. A summary of the results from testing various overfire air configurations are given in Figure 1. As anticipated, the implementation of global air staging results in a significant reduction in furnace outlet NO_x emissions. Beginning with NO_x emissions of 0.52 pounds/MM Btu with a typical "baseline" (post-NSPS) firing system arrangement, NO_x reductions continued to a low of 0.13 pounds/MM Btu for an "optimized" TFS 2000™ firing system arrangement (Note: similar 0.13 pounds/MM Btu outlet NO_x emissions were obtained with the upper SOFA only, but this was at slightly degraded carbon in the fly ash performance). The "optimized" TFS 2000™ system incorporates improvements to the bulk

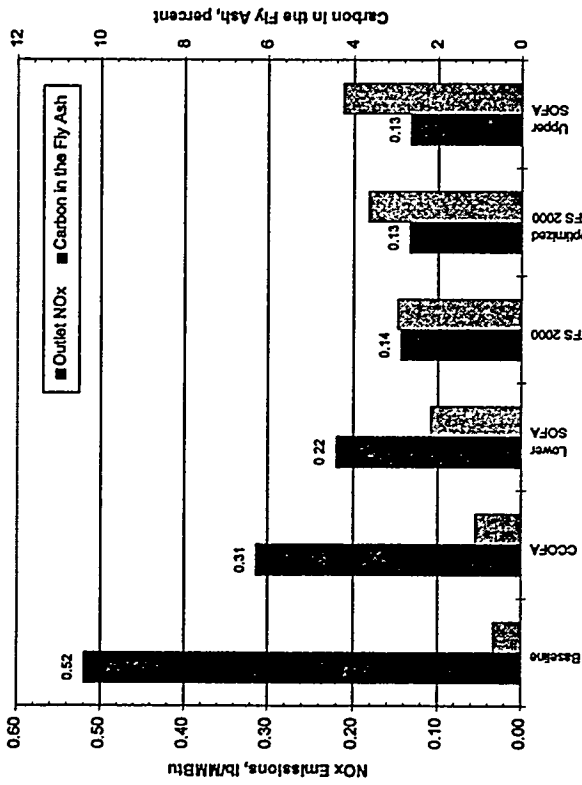


Figure 1 Global Staging

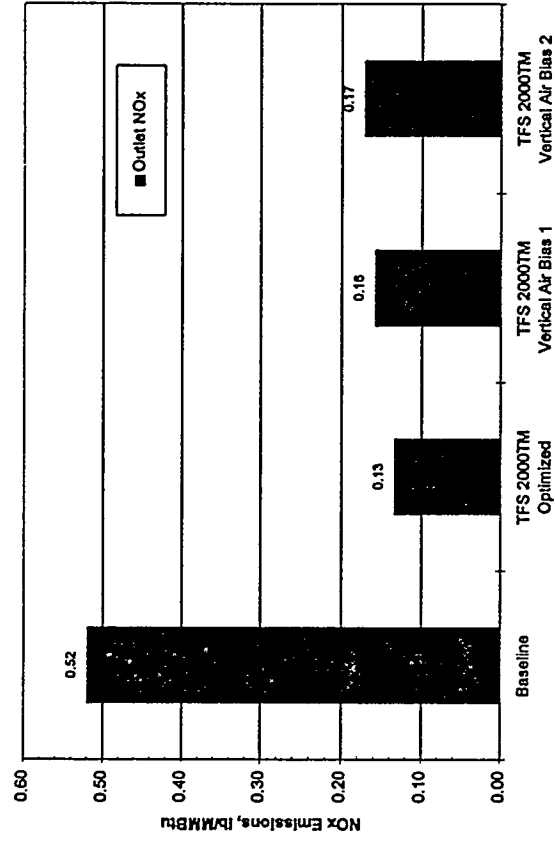


Figure 2 Effects of Vertical Staging on NOx

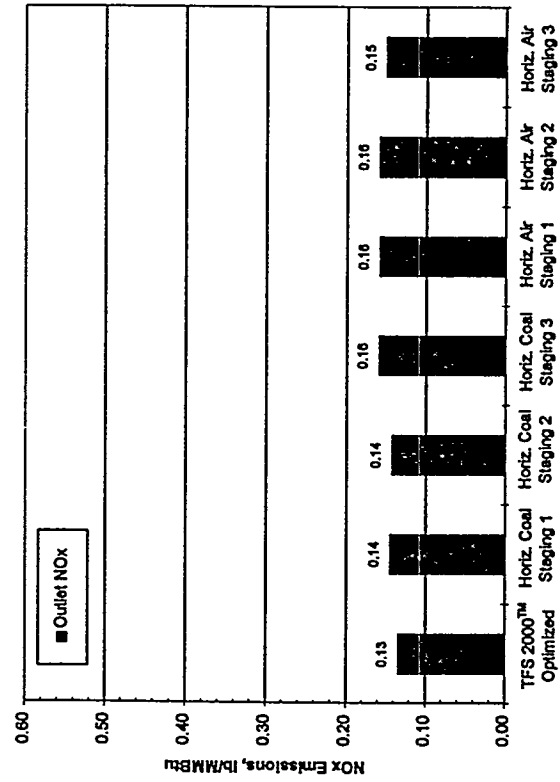


Figure 3 Effects of Horizontal Staging on NOx

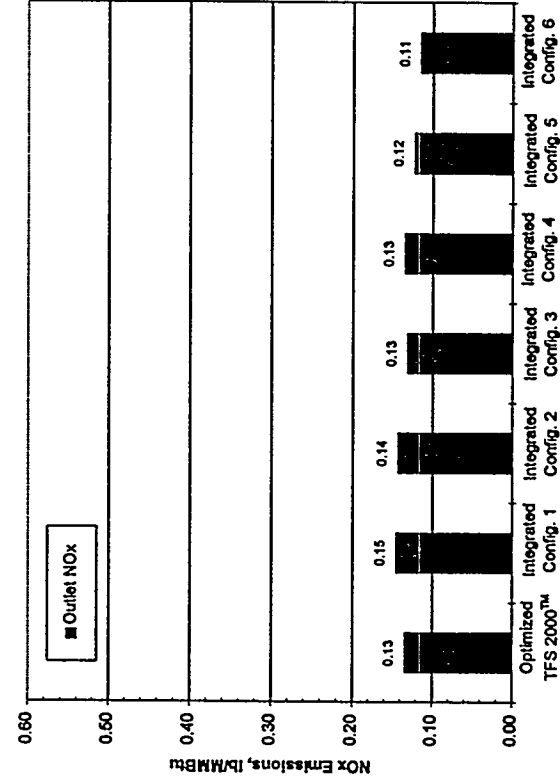


Figure 4 Effects of Integrated Staging on NOx

stoichiometry history. In all, a 75% reduction in NO_x from baseline levels was achieved with the "optimized" TFS 2000™ system. As expected, carbon in the fly ash increased as the global staging was increased, but remained below the limit of 5%.

Having benchmarked the effects of global staging on firing system performance, both vertical and horizontal staging techniques within the main firing zone were subsequently tested. The objectives of this work were to confirm the results of prior main windbox vertical air staging work, and to further reduce outlet NO_x emissions from the previously demonstrated "best" level of 0.13 pounds/MM Btu. As such, these methodologies were applied in concert with the "optimized" TFS 2000™ firing system, keeping the global stoichiometry history constant to allow meaningful comparisons.

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Next, horizontal staging, used to control the horizontal "build-up" of stoichiometry (corner to corner) within the main burner zone, was evaluated. This was accomplished by biasing the fuel and air between one or more of the four corners. Tested subsets of this technique are two corner firing, where all of the air and fuel are injected through two of four corners in a tangential arrangement, and opposed corner firing where the coal is injected from two corners, and the air from the remaining two. In general, independent implementation of horizontal staging techniques resulted in neutral to degraded NO_x emission performance over that of the "optimized" TFS 2000™ firing system. This is seen in Figure 3. These results demonstrate that, similar to the prior vertical staging experiments, outlet NO_x emissions can be affected by horizontal fuel and air distributions. However, these results also demonstrate that the global time - stoichiometry history (i.e., the TFS 2000™ stoichiometry profile) dominates the NO_x formation and reduction processes at these levels of global air staging.

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The goals of this task are listed below in order of priority. It is desirable that these goals be achieved simultaneously.

- Particulate emissions of less than 0.005 lb/MM Btu

- Maximum filter clean-side draft loss of 8 inches w.g. at 4 ft/min at 775°F
- Operation with a Filter Face Velocity (FFV) of at least 4 ft/min at 650°F
- Minimum of 80 % NO_x removal efficiency
- Ammonia slip of less than 15 ppm

Information gained from demonstration and evaluation will address the following issues:

- Confirm filter particulate removal efficiency.
- Determine the tubesheet differential pressure (filter draft loss) as a function of face velocity, cleaning cycle characteristics, operating time, and other parameters.
- Determine the NO_x reduction efficiency as a function of flue gas composition (NO_x inlet concentration, NH₃ stoichiometry, particulate removal), and flue gas temperature. Of further interest is the determination of the requirements to maintain the catalytic conversion efficiency.

Approach. The approach used is to test the catalytic filter system with four filter modules on a 100 ACFM (165 m³/hr) slipstream at Richmond Power & Light's Whitewater Valley Station Unit 2, a 66 MWe pulverized coal-fired boiler. CeraMem manufactured the ceramic filter modules and Engelhard applied the NO_x reduction catalyst. At this writing, an initial 500-hour test has been concluded, in which both particulate removal and NO_x reduction were investigated.

Preliminary Results. *The tubesheet differential pressure* (filter draft loss) is considered an essential element to the success of the catalytic filter. For the first 500-hour test, the initial tubesheet differential pressure was approximately 16 inches w.g. (FFV=4 ft/min, T= 650°F). The filter permeance, a parameter inversely proportional to tubesheet differential pressure and independent of filter face velocity and process temperature, decreased through the first 150 hours of operation, as shown in Figure 5. This decrease indicated that the filter tubesheet differential pressure increased at constant process conditions, an effect that is typical of all ceramic particulate filters. This decrease in permeance or increase in tubesheet differential pressure is caused by the smaller particulate (less than 0.5μ diameter) becoming permanently lodged in the filter substrate. For all ceramic particulate filters, the filter permeance should stabilize at some point, indicating that essentially the pores that are able to become "plugged" have been, and that the filter is being cleaned efficiently. At this point, the tubesheet differential pressure will remain constant at constant process conditions. In the case of the initial 500-hour test, the tubesheet differential pressure rose to approximately 23-24 inches w.g. (FFV=4, T=650°F) after approximately 200 hours of operation and was stable for the remainder of the test.

Upon conclusion of the 500-hour test, the system was opened and the filter modules were inspected. Visual inspection showed that the filters were being cleaned effectively, with no particulate buildup being detected and no plugged channels being found. Subsequent analysis of the catalytic filters indicate that catalyst addition was responsible for approximately 75 % of the tubesheet differential pressure.

Particulate removal for this filter system was expected to be near absolute. In previous laboratory testing outlet emissions from the filter could not be detected using a laser light-scattering measurement system, indicating that removal efficiency exceeded 99.99994%. In the 500-hour test, two outlet particulate samples were taken, with results indicating a removal efficiency of 99.93% which is below the expected value. Upon completion of the 500-hour test, the unit was opened and the tubesheet and vessel inspected. Lack of particulate matter on the "clean-side" of the tubesheet, particularly in cracks and crevices, tends to indicate that particulate matter was not passing through the filters and that the sampling results were reflective of material that had been left in the ducts when the system was being bypassed.

NO_x Reduction Efficiency testing was initiated after approximately 350 hours of operation. Ammonia was injected into the system to facilitate the NO_x reduction reaction. Inlet and outlet ammonia sampling was conducted to quantify ammonia injection rates and ammonia slip, while NO_x inlet and outlet concentrations were determined using two ThermoElectron Model 10 NO_x CEMs. Due to vendor problems that are beyond the scope of the paper, maximum injection stoichiometry was limited to 0.4 (maximum ammonia concentration in the inlet flue gas was approximately 200 ppm). Preliminary results indicate that the catalyst made efficient use of the ammonia, as shown in Figure 6. The ammonia was fully accounted for in the NO_x reduction reaction, and sampling and analysis found less than 3 ppm in the outlet flue gas in all samples.

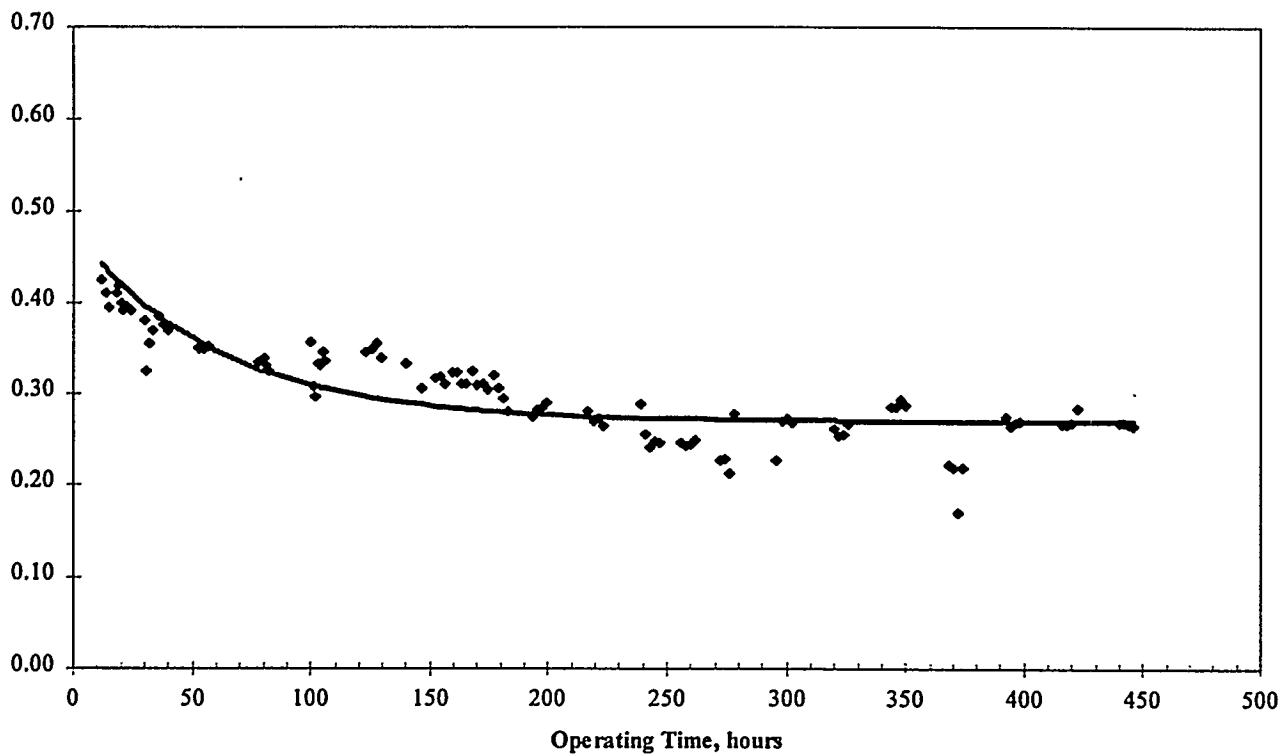


Figure 5 - Filter Permeance vs. Operating Time

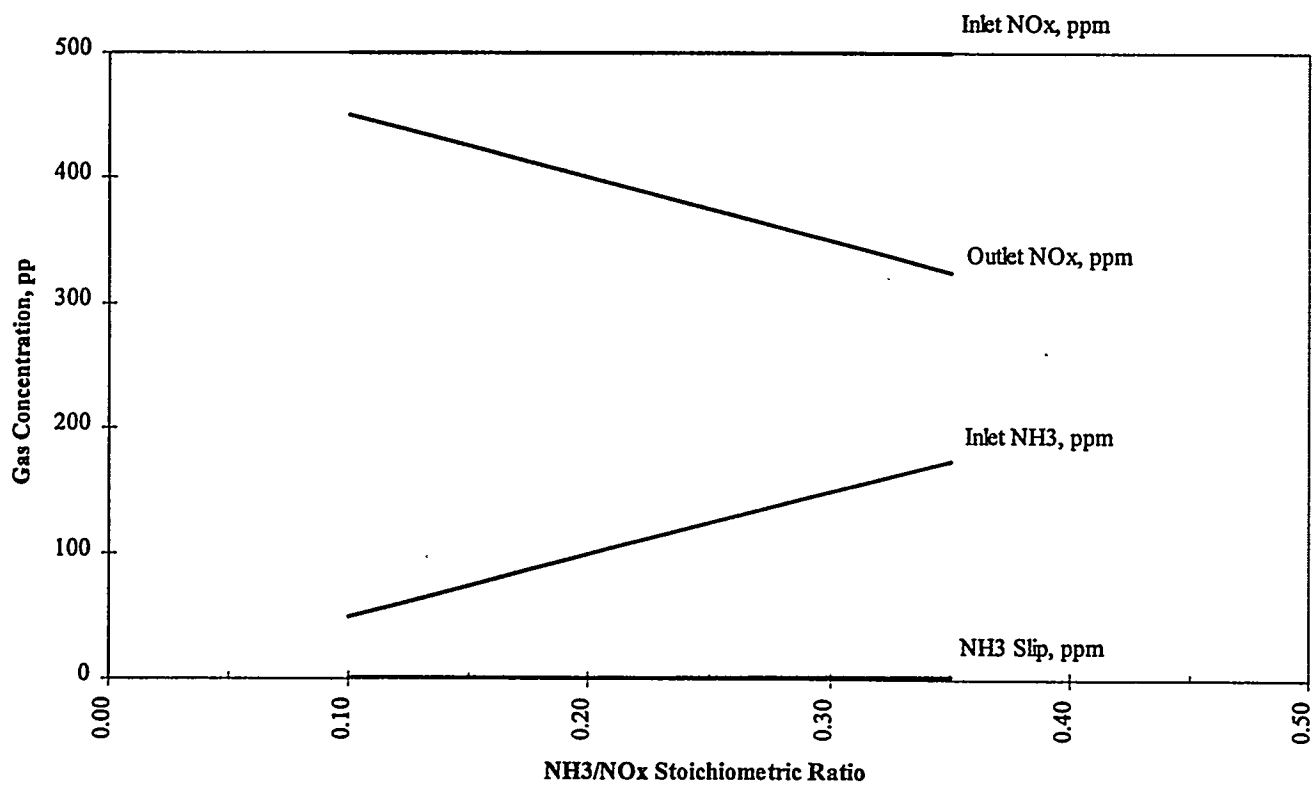


Figure 6 - NO_x Reduction

Future Tests. It is unlikely that an advancement in catalyst deposition technology will be made that will achieve an initial tubesheet pressure differential of less than 8 inches w.g. within the 100 ACFM Test time frame. A second 500-hour test will be conducted to gather engineering data on the performance of a non-catalytic filter system. Catalyst development is continuing in a parallel program, with the hope of being able to achieve project goals by completion of Phase II.

POCTF DESIGN AND LICENSING WITH A KALINA CYCLE

Introduction. The centerpiece of the LEBS project is Phase IV which will undertake the design, construction and test operation of a proof-of-concept test facility (POCTF). These final-phase activities will provide the design and operating database critical to commercialization of the LEBS technologies. At present, the team is developing a site-specific preliminary design for their POCTF, and has project licensing in progress.

Project Description. The team was fortunate in obtaining a commitment for an outstanding host site for the POCTF. Richmond (Indiana) Power & Light Co. (RP&L) has offered to host the project at their Whitewater Valley station. RP&L has a history of successful involvement in technology demonstration programs, including one of the earliest low NO_x burner installations, a LIMB installation, and a Clean Coal Technology project.

The Whitewater Valley plant is composed of two coal-fired, non-reheat units, with nominal ratings of 33 MWe (Unit 1) and 66 MWe (Unit 2). Unit 1 will be modified to accept the LEBS technology package. This unit is approximately 40 years old, and incorporates a 900F/900 psig steam cycle with a steam capacity of 325,000 lb/hr. The POCTF project will involve a major restructuring of the unit, that entails the replacement of the complete power system (boiler, turbine-generator, feedwater heaters, power piping) with a new Kalina-based power system, and addition of the LEBS flue gas cleanup system. The project will use the plant infrastructure to the maximum extent practical, including coal handling, heat rejection, ash handling, powerhouse structures, and auxiliary systems. Although the project is being implemented as a test facility, RP&L intends to use the unit for long-term production service following completion of the LEBS project. This criterion, therefore, has a dominant effect on specification and design of the equipment and the facility. The approach taken in establishing the size of the modified unit has been to maximize its generating capacity, consistent with making maximum use of existing plant infrastructure. Key plant performance parameters are summarized in Table 2.

By leveraging the significant improvement in heat rate offered by the Kalina cycle with a modest 10% increase in coal heat input, the unit output will be increased a substantial 43% to about 48 MWe, with a corresponding 23% decrease in heat rate. At the projected net unit heat rate of about 9,200 Btu/kWh, the modified Whitewater Valley Unit 1 will be the most efficient coal-fired unit of its size in the U.S. The planned project, in fact, compares favorably to the best coal-fired unit heat rate reported in the USA in 1994 of 8,889 Btu/kWh (annual average) for a 660 MW supercritical unit.

Equipment. Because the Kalina cycle optimizes at different thermodynamic conditions than a steam cycle, and because of the change in working fluid and the increase in generating capacity, the complete steam side of the power cycle is to be removed and replaced. Equipment to be replaced includes the boiler and auxiliaries, turbine-generator and auxiliaries, condenser, condensate system and feedwater system. The size of the unit has been selected such that the new vapor generator will fit in the existing boiler support-steel cavity, and the new turbine-generator will fit the existing turbine pedestal (after pedestal modification). The fact that the Kalina cycle regenerates substantially more heat than a steam cycle results in a significant increase in the number of regenerative heaters, such that a turbine hall addition will be required to house this new equipment.

The vapor generator, or boiler, design for the POCTF is a single reheat, drum type with pumped circulation for cooling furnace wall evaporative tubes. The Kalina cycle, with its higher rate of heat regeneration, requires less evaporation but more superheater and reheater duty in the vapor generator. Thus, in addition to pendant and horizontal superheater and reheater surfaces, in the preliminary design portions of the upper furnace walls are used for superheating and reheating the working fluid. The design of these sections is the same as conventional radiant wall reheater designs. The vapor generator looks very much like a large utility unit designed for a Rankine cycle.

Turbine design and performance for a Rankine or Kalina cycle are very similar. Ammonia has a molecular weight very close to that of pure water, (17 vs. 18). This allows the use of current designs for turbine blading and turbine shell to be used in a Kalina cycle. One major difference in the turbine, when used in a Kalina cycle, is that the turbine is changed to a back pressure configuration. In doing so, there is no need for the large low pressure section and vacuum system which are required in the Rankine cycle. This provides a capital cost saving as well as improved system efficiency.

TABLE 2 - UNIT 1 PERFORMANCE PARAMETERS
(Preliminary)

		<u>Existing</u>	<u>POCTF</u>	<u>Change</u>
Coal Heat Input	MM Btu/hr	400	440	+ 10%
Cooling Tower Load	MM Btu/hr	216	215	
Generator Output	MWe	35.6	54.6	
Auxiliary Load	MWe	2.2	6.7	
Net Unit Generation	MWe	33.4	47.9	+ 43%
Net Unit Heat Rate	Btu/kWh	12,000	9,186	- 23%

In addition, the inclusion of the LEBS flue gas emissions control features dictates removal of the gas side power cycle systems. The replacement systems will include the low NO_x firing technology described previously, a new draft system, and a flue gas cleanup system. At present, two alternative processes are being evaluated for flue gas cleanup: the SNO_xTM hot process and an advanced dry-scrubbing process.

Control requirements associated with the Kalina power cycle, and the fact that Unit 1 still has its original control system, dictate that the project will include installation of a new unit-wide distributed control system. The increase in auxiliary power consumption associated with the modified unit also requires that the station service transformers for Unit 1 (unit auxiliary and startup) be replaced with larger capacity units, and substantial new power distribution capability be added.

Licensing. A licensing plan and schedule have been developed for the project that has identified the need to obtain twelve individual environmental/safety permits and approvals. The project will result in large reductions of all the regulated air emissions from Unit 1. Thus, approvals for the air permits are expected to be relatively straight forward. Unique to this power project, however, is the significant ammonia inventory required for operation of the Kalina cycle. The presence of this material on site will require the development of plans to deal with a potential accidental ammonia release.

CONCLUSIONS AND FUTURE WORK

Testing of the low-NO_x firing system has been completed. The work remaining is analysis of data from the second week of testing in the BSF. The NO_x emission target of 0.1 lb/MM Btu with <5% carbon in the fly ash was achieved in the BSF (actually 0.11 lb). However, at this time it cannot be predicted with certainty that 0.1 lb/MM Btu will be achieved in commercial size systems. There presently is no further LEBS firing system development work planned prior to construction of the POCTF.

The preliminary results of the catalytic filter field testing were very encouraging regarding particulate emissions and NO_x reduction. However, measured gas draft loss was excessive. Since approximately 75% of the draft loss is attributed to the catalyst, testing will continue with a non-catalytic filter system while catalyst deposition technology is reviewed. Also, since it is possible that the catalytic filter draft loss situation may not be resolved within the POCTF schedule, an alternative technology will be evaluated.

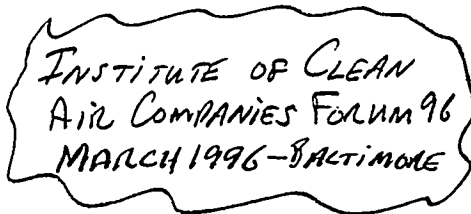
The POCTF preliminary design work will be completed within the project schedule. A full release for detailed engineering, manufacturing, etc. is expected in mid to late 1997.

REFERENCES

1. J. W. Regan., et al, "ABB's LEBS Activities - A Status Report", First Joint Power & Fuel Systems Contractors Conference, Pittsburgh, PA, 1996

APPENDIX D - 17 pages

ADVANCEMENTS IN LOW NO_x TANGENTIAL FIRING SYSTEMS



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Abstract

The most cost effective method of reducing nitrogen oxide emissions when burning fossil fuels, such as coal, is through in-furnace NO_x reduction processes. ABB Combustion Engineering, Inc. (ABB CE), through its ABB Power Plant Laboratories has been involved in the development of such low NO_x pulverized coal firing systems for many years. This development effort is most recently demonstrated through ABB CE's involvement with the U.S. Department of Energy's (DOE) "Engineering Development of Advanced Coal Fired Low-Emission Boiler Systems" (LEBS) project.

The goal of the DOE LEBS project is to use "near term" technologies to produce a commercially viable, low emissions boiler. This paper addresses one of the key technologies within this project, the NO_x control subsystem. The foundation for the work undertaken at ABB CE is the TFS 2000™ firing system, which is currently offered on a commercial basis. This system encompasses sub-stoichiometric combustion in the main firing zone for reduced NO_x formation. Potential enhancements to this firing system focus on optimizing the introduction of the air and fuel within the primary windbox to provide additional horizontal and vertical staging. As is the case with all in-furnace NO_x control processes, it is necessary to operate the system in a manner which does not decrease NO_x at the expense of reduced combustion efficiency. The objective of developmental work on the low NO_x firing system is to reduce NO_x emissions levels leaving the boiler to 0.10 pounds NO_x / MMBtu while maintaining carbon in ash at acceptably low levels (<5%) for high sulfur, mid-western and eastern bituminous coals.

The approach used to evaluate the various firing systems concepts included kinetic and computational modeling, small scale experimental testing in a Fundamental Scale Burner Facility (FSBF), and larger scale combustion testing in a Boiler Simulation Facility (BSF.) Both modeling and experimental testing were applied to better understand the mechanisms governing in-furnace NO_x reduction and to identify potential enhancements to the TFS 2000™ firing system. This paper presents an overview of the approach used in the development of an advanced low NO_x firing system and results from the experimental testing of that system.

Introduction

Combustion Engineering, Inc. (ABB CE) is one of three contractors participating in the DOE's LEBS project. The overall objective of this project is the improvement of the environmental performance of pulverized coal fired power plants, without adversely impacting efficiency or the cost of electricity. One of the key elements within the LEBS project is the NO_x control subsystem, for which the specific goals are the reduction of nitrogen oxides (NO_x) emissions leaving the primary furnace to 0.10 pounds/ MMBtu or lower while maintaining carbon in ash levels at 5% or less.

For the LEBS project, the DOE has specified the use of near term technologies, which are at least partially developed, to provide these overall emissions reductions. Based on technical and economic feasibility, advanced tangential firing was selected as the primary means of NO_x emissions control [1,2] for ABB CE's LEBS boiler design. Specifically, ABB CE's TFS 2000™ firing system, which is a proven technology and commercially available, represents the technology selected as the basis for in-furnace NO_x reduction. This firing system design has been demonstrated to provide NO_x emissions of 0.20 pounds/ MMBtu in prior laboratory and full scale, retrofit, utility boiler applications [3,4].

Briefly, the TFS 2000™ firing system has been developed for minimum NO_x emissions from pulverized coal fired boilers, accomplished by way of combustion techniques only. Specific features of this system include the use of concentric firing system (CFS) air nozzles, where the main windbox secondary air jets are introduced at a larger firing circle than the fuel jets; close coupled over fire air (CCOFA) for improved carbon burnout; and multi-staged separated over fire air (SOFA) to provide for complete combustion while maintaining an optimum global stoichiometry history for NO_x control. In addition, the TFS 2000™ firing system includes flame attachment coal nozzle tips for rapid fuel ignition and a pulverizer configured with a Dynamic™ Classifier to produce fine coal to minimize carbon losses under these staged combustion conditions.

Approach

The plan for reducing NO_x emissions under the LEBS project was to enhance the TFS 2000™ firing system, focusing on optimizing the introduction of the air and fuel within the primary windbox. These enhancements were based on controlling the combustion of the coal in a more local sub-stoichiometric environment. That is, in addition to the global staging currently applied, improved NO_x reduction was sought by controlling and optimizing the mixing of the fuel and air locally within the main firing zone through vertical and horizontal staging techniques. Vertical staging was done by biasing the air and fuel within the main windbox to control/ optimize the rate of the vertical stoichiometry build-up in this region. Similarly, horizontal staging was done by biasing the air and fuel distribution between each of the four windbox corners as a means of controlling the horizontal stoichiometry build-up from corner to corner within the firing zone. As a result of these enhancements, the residence time/ stoichiometry history of the coal combustion is controlled on a more local scale and the resultant formation of NO_x minimized. In addition to these enhancements, newer, more novel firing systems

such as two corner firing (the injection of air and coal through only two of the normal four corners in a tangentially fired system) were evaluated as a means of providing additional NO_x reduction.

The processes used in the development and evaluation of the various firing system concepts/ configurations included an integrated approach of chemical kinetic and computational modeling, small scale experimental testing in a Fundamental Scale Burner Facility (FSBF), and larger scale experimental testing in a Boiler Simulation Facility (BSF).

A 1-D (time) chemical kinetics reaction model was used to evaluate and screen the effects of vertical staging within the main windbox on overall NO_x production in order to optimize the vertical stoichiometry build up. Results from this modeling were applied to the development of advanced fuel staging concepts which were subsequently evaluated in small scale combustion testing (6.1 MMBtu/ hour) performed in the FSBF. Additional screening and development of new, novel firing systems employing horizontal staging in the main firing zone was accomplished using 3-D computational fluid dynamic (CFD) modeling. In this modeling, the furnace aerodynamics, mixing, and stoichiometry history (gas side performance) of these various concepts were evaluated to assess the potential for additional reduction in NO_x emissions. The results from the kinetic modeling, small scale combustion testing, and CFD modeling were used to provide the information necessary for the development of the LEBS NO_x control subsystem design strategy. These designs were subsequently tested and evaluated in larger, pilot scale testing (50 MMBtu/ hour) in the BSF. A flow diagram of this integrated approach is shown in Figure 1.

Discussion of Results

Kinetic Modeling

In order to evaluate the effects of various firing system arrangements on total NO_x formation, a 1-D kinetic model which utilizes the CHEMKIN code was first applied. This model employs a series of plug flow reactors suitable for simulating the staged introduction of fuel and air within the main windbox. Chemical kinetic mechanisms of Miller and Bowman [5] were used in this model to evaluate the effects of stoichiometry, residence time and temperature history on NO_x formation and destruction. The evaluation of these results, though qualitative, served as an important screening tool for identifying promising concepts.

Results from the chemical kinetic modeling work indicated that, although bulk main windbox stoichiometry is the primary influence on overall NO_x emissions, the stoichiometric build up in the main windbox zone has a significant influence on NO_x formation and reduction. That is, for similar bulk windbox stoichiometries, the cumulative sequencing of fuel and air in the main firing zone influences the overall NO_x emissions. In other words, although it is the global stoichiometry history that dominates the overall NO_x formation and reduction process, the build up of stoichiometry within the windbox zone is also a significant contributor. This is illustrated in Table 1, where the predicted NO_x values are given for a series of

configurations, each with the same main burner zone and global bulk stoichiometries. The only differences in each of these configurations is the stoichiometry build up within the main windbox zone. As can be seen from this data, a variation of nearly $\pm 30\%$ of the average predicted NO_x was found to exist as the cumulative stoichiometry sequencing was varied. The results of vertical staging from this modeling were applied in firing system designs and subsequently evaluated / demonstrated in small scale combustion testing in the FSBF.

Table 1 - Predicted NO_x for Similar Main Burner Stoichiometries

<u>Description</u>	<u>Predicted NO_x</u>
Configuration 1	74
Configuration 2	79
Configuration 3	88
Configuration 4	92
Configuration 5	135

Small Scale Combustion Testing

In order to evaluate the effects of integrating advanced fuel staging scenarios in the main windbox, and to explore additional preliminary concepts of vertical staging, small scale combustion testing was performed in ABB Power Plant Laboratories Fundamental Scale Burner Facility (FSBF). The objective of the FSBF testing was to evaluate the NO_x emissions and combustion performance from firing systems that capitalize on the reburn process within the main windbox zone. Additionally, testing was performed to evaluate the effects of residence time on NO_x reduction on the test coal, analysis shown in Table 2, and to screen concepts for larger scale pilot testing in the Boiler Simulation Facility (BSF).

The FSBF is a horizontally fired cylindrical test furnace, with adjustable length, capable of firing up to 9.9 MMBtu/ hour thermal input. For this testing, the furnace was configured for four corner, tangential firing. Three elevations each of coal and auxiliary air comprised the main burner region, and up to five elevations of over fire air were available to model various globally staged furnace configurations. A furnace firing rate of nominally 6.1 MMBtu/ hour and overall length were selected to simulate the mixing history (residence time and temperature) representative of typical commercial applications. A schematic of this facility is shown in Figure 2.

Low NO_x firing typically requires that combustion in the main burner zone (MBZ) be performed under sub-stoichiometric conditions. In addition, the available residence time under these sub-stoichiometric conditions is an important factor in determining the magnitude of these NO_x emission. As such, various conventional global air staging techniques were tested to benchmark their effectiveness on NO_x reduction for

the test fuel. Outlet NO_x emissions as a function of staged residence time and bulk MBZ stoichiometry, on this test fuel in the FSBF, are presented in Figure 3. As expected, lower outlet NO_x emissions are achieved under sub-stoichiometric combustion conditions in the MBZ, with up to a 70% reduction when compared against baseline, unstaged conditions. In addition to stoichiometry, it is also seen in this Figure that the location of the over fire air injection is an important factor in determining the magnitude of NO_x emissions. Specifically, lower NO_x emissions were obtained under similar levels of staging (same MBZ stoichiometry) when the introduction of over fire air is moved further downstream from the final coal elevation, thereby increasing sub-stoichiometric residence times in the furnace.

Additional testing was performed to determine the effects of over fire air residence time on overall NO_x emissions. This was accomplished by maintaining the bulk main burner zone stoichiometry constant while varying the location of a single elevation of separate over fire air (SOFA). Results from this testing, shown in Figure 4, indicate that the largest reduction rate in NO_x emissions occurs over a short bulk residence time (determined from the upper elevation of fuel injection), with diminishing returns in overall NO_x reduction as the over fire air residence times are increased.

After having benchmarked various global staging arrangements in the FSBF for this test fuel, testing was performed to evaluate the effects of vertical staging in the main windbox zone on overall NO_x formation. MBZ vertical staging was accomplished by strategically biasing the air and fuel distribution within the windbox, thus controlling the stoichiometry sequencing in the main combustion zone, while holding the bulk main burner zone stoichiometry constant, and was performed for several staged furnace arrangements. Results from this testing indicate that controlling the stoichiometry sequencing in the main burner zone had a significant impact on outlet NO_x emissions, as shown in Figure 5. Specifically, limiting the peak stoichiometries within the main windbox zone was shown to be important in controlling overall NO_x formation. As seen in this Figure, outlet NO_x emissions varied by more than 20% for similar globally staged furnace arrangements. These variances were due to the differences in the rate of change of the MBZ stoichiometry only, and correspond with the prediction of the chemical kinetic modeling.

The results from this FSBF testing were used to identify potential enhancements to the TFS 2000™ firing system and later employed in the pilot scale combustion testing.

Computational Fluid Dynamic Modeling

3-D computational fluid dynamic modeling (CFD) was also used in the development and evaluation of advanced firing system concepts. CFD modeling allows advanced firing system concepts to be evaluated in a more cost effective manner than pilot-scale testing. The insight gained from the computational models helps to screen potential firing system concepts and better focus the experimental testing. As part of this project, CFD modeling was used to evaluate advanced horizontally staged firing concepts, such as two (2) corner coal firing. All CFD simulations were performed with the FLUENT code using the coal combustion and radiative heat transfer submodels.

Proprietary user-defined subroutines developed for use with the FLUENT code were also used in the CFD analyses.

Prior to evaluating any of the advanced firing system concepts, a CFD simulation of an existing TFS 2000™ firing arrangement, in the BSF, was performed. Results from this simulation were compared to previously obtained experimental data, and the model's thermal boundary conditions modified to assimilate the furnace temperature history. Once the model was representative of the experimental data for this TFS 2000™ configuration, all subsequent modeling results were benchmarked against this arrangement. In each subsequent case, boundary conditions were held constant in order to qualitatively evaluate the effects of the various new firing systems on the furnace gas side performance.

As part of the screening process, various combinations of vertically and horizontally staged furnace arrangements were computationally modeled. Results from each of these simulations were analyzed and benchmarked against the TFS 2000™ simulation. The primary objective of this modeling was to evaluate the impacts of firing system modifications on furnace aerodynamics and emissions reduction potential. Specifically, the gas flow, gas species, and temperature distributions within the furnace, along with furnace outlet temperatures, were examined for each of the arrangements and compared to the TFS 2000™ configuration. In addition, coal particle trajectories from each of the individual coal nozzles were examined. Included in this analysis were the coal particle stoichiometry, temperature, and residence time histories to assess the impacts of the various firing system modifications on reduced NO_x emissions potential. Typical BSF coal particle trajectories for a single coal nozzle are shown in Figure 6. These simulations were also used to assess effects of the advanced firing system arrangements on wall heat flux distributions and their potential impacts on waterwall circulation in order to guide in the selection of optimum firing system designs. Finally, the potential for water wall corrosion/ slagging for each of these systems was examined by way of the predicted particle concentrations and gas phase stoichiometry along the furnace walls for additional guidance in the firing system design.

Briefly, the modeling results indicated that many of the proposed horizontal firing arrangements were viable when applied to the BSF geometry, though visible differences in the gas flow, species and temperature distributions in the main windbox zone were predicted, when compared against the TFS 2000™ arrangement. As a result of these differences, significant changes in wall heat flux patterns and particle concentrations at the wall resulted. However, modifications to the promising new firing system concepts were performed which resulted in peak values that, although appearing at different locations in the furnace, were not much different than those for the TFS 2000™ arrangement.

In summary, the modeling results suggested several of the horizontal staging concepts showed potential for reduce NO_x formation, without negatively affecting furnace performance, and warranted further evaluation in ensuing combustion testing in the

BSF. In addition, the modeling provided general insight into the performance of these systems, better focusing the experimental testing.

Pilot Scale Combustion Testing

Pilot scale combustion testing of in-furnace NO_x control systems was performed in ABB Power Plant Laboratories' Boiler Simulation Facility (BSF). The objective of this testing was to evaluate enhancements to the existing NO_x control technologies for improved NO_x emissions performance, while providing the necessary information for supporting the design of the NO_x control subsystem for the LEBS Proof of Concept Test Facility (POCTF).

The BSF is a pilot scale test furnace, nominally rated at 50 MMBtu/ hour (5 MWe) for coal firing, that reliably duplicates the combustion characteristics of a tangentially fired utility boiler. All major aspects of a typical tangentially fired utility boiler are duplicated in the BSF including a "V" hopper for bottom ash collection, the use of multiple burner elevations, and an arch with subsequent backpass convective "superheat," "reheat," and "economizer" surfaces. Selective refractory lining over atmospheric pressure "waterwalls" allows the matching of the residence time / temperature history of large scale utility boilers, including the horizontal furnace outlet plane (HFOP) gas temperature, within the BSF.

The BSF is fully instrumented to monitor the combustion process. Instruments for measuring coal feed rate, primary and individual secondary air mass flow rates, outlet emissions (O₂, CO₂, CO, SO₂, NO, and NO_x), and convective pass heat flux distribution are tied into a combined DCS / data acquisition system to allow for control and logging of these and other important operational parameters. For the subject testing, the BSF was operated in a tangentially fired mode with multiple levels of available separated over fire air (SOFA), as depicted in Figure 7. Prior laboratory test programs have shown that BSF test results can be reliably translated to the field for use in firing system design, and subsequent performance prediction [3].

Performance targets for the BSF combustion testing were consistent with those for the LEBS program; NO_x emissions <0.10 pounds/ MMBtu and carbon in the fly ash <5% for high sulfur, mid-western and eastern bituminous coals. In addition, the lower furnace heat absorption profiles and convective pass heat flux distribution were to remain similar to or improved over the existing system. The coal utilized during the BSF testing was the high sulfur, medium volatile, eastern bituminous Viking coal from Montgomery, Indiana. An analysis of the Viking coal is given in Table 3.

Prior to the initiation of NO_x control subsystem testing, the firing system for the BSF was modified to take advantage of current and previous R&D project findings. First, ABB CE's Aerotip™ coal nozzle tip design was utilized as the base from which the BSF coal nozzles were constructed. The Aerotip™ design embodies improved aerodynamic features to minimize tip distortion, overheating, and coal deposition related problems. Also, it supports the test programs need for a low NO_x coal nozzle tip through its control over near field stoichiometry.

In addition to the incorporation of an Aerotip™ based coal nozzle tip, the main windboxes of the BSF were designed to accommodate a range of vertical and horizontal air and coal staging scenarios. The design of the secondary air nozzles was based on the need to maintain proper jet momenta, while having sufficient flexibility to test variations in vertical and horizontal air staging. In addition, excess coal nozzle capacity was incorporated to allow the testing of various coal staging scenarios, including two corner coal firing. With this foundation, each of the "base" (r.e. benchmark) firing system designs tested in the BSF, including the TFS 2000™ firing system, was able to incorporate the results of the prior chemical kinetic and small scale (FSBF) combustion testing with respect to main windbox vertical air staging.

One goal of the BSF testing was to generate design data in support of achieving NOx emissions of 0.10 pounds/ MMBtu through in-furnace firing system modifications (i.e. prior to any post combustion process NOx reduction system). Toward this end, various "conventional" global air staging techniques were tested in order to benchmark their NOx reduction potential on the test fuel. This work included investigations of close coupled over fire air (CCOFA), upper and lower (single) elevations of separated over fire air (SOFA), and an implementation of ABB CE's TFS 2000™ technology. All of the varied over fire air configurations utilized the same main windbox arrangement, and all were performed with high fineness (90% - 200 mesh) coal grind, which is consistent with TFS 2000™ firing system design standards.

A summary of the results from testing various over fire air configurations with the test coal are given in Figure 8. As anticipated, the implementation of global air staging results in a significant reduction in furnace outlet NOx emissions. Beginning with NOx emissions of 0.52 pounds/ MMBtu with a typical "baseline" (post-NSPS) firing system arrangement, NOx reductions continued to a low of 0.13 pounds/ MMBtu for an "optimized" TFS 2000™ firing system arrangement (Note: similar 0.13 pounds/ MMBtu outlet NOx emissions were obtained with the upper SOFA only, but this was at slightly degraded carbon in the fly ash performance). The "optimized" TFS 2000™ system incorporates improvements to the bulk stoichiometry history over the initial TFS 2000™ test, with identical main and over fire air windbox configurations. In all, a 75% reduction in NOx from baseline levels was achieved with the "optimized" TFS 2000™ system. As expected, carbon in the fly ash increased as the global staging was increased, but remained below the performance limit of 5%.

Having benchmarked the effects of global staging on firing system performance, both vertical and horizontal staging techniques within the main firing zone were subsequently tested to evaluate their effects on NOx performance. The objectives of this work were to confirm the results of prior main windbox vertical air staging work, and to further reduce outlet NOx emissions from the previously demonstrated "best" level of 0.13 pounds/ MMBtu through the application of horizontal, and integrated vertical and horizontal main windbox staging techniques. As such, these methodologies were applied in concert with the optimized TFS 2000™ firing system, keeping the global stoichiometry history constant to allow meaningful comparisons.

First, vertical air staging within the main windbox was independently varied to demonstrate its effect on NO_x formation at this large pilot scale. Results from this testing, given in Figure 9, show that significant variation in NO_x emissions occur as main windbox vertical air staging is changed. In this case variations to the vertical air staging produced a +/- 13% deviation in outlet NO_x about the mean. This result confirms that the main windbox vertical stoichiometry history is an important contributor to overall NO_x formation, even with significant levels of global air staging. Overall, NO_x emissions increased when variations to the main windbox vertical stoichiometry build-up were applied to the previously optimized TFS 2000™ arrangement. This result is, however, expected since the “optimized” TFS 2000™ system incorporates the results of prior chemical kinetic and small scale combustion test vertical air staging work into the configuration of its main windbox as noted above.

Next, horizontal staging, used to control the horizontal “build-up” of stoichiometry (corner to corner) within the main burner zone, was evaluated. This was accomplished by biasing the fuel and air between one or more of the four corners. Tested subsets of this technique are two corner firing, where all of the air and fuel are injected through two of four corners in a tangential arrangement, and opposed corner firing where the coal is injected from two corners, and the air from the remaining two. In general, independent implementation of horizontal staging techniques resulted in neutral to degraded NO_x emissions performance over that of the optimized TFS 2000™ firing system during the subject testing. This is seen in Figure 10, which shows the effect of independent variation of either fuel or air (horizontal staging) on overall NO_x emissions performance. These results demonstrate that, similar to the prior vertical staging experiments, outlet NO_x emissions can be affected by horizontal fuel and air distributions. However, these results also demonstrate that the global time - stoichiometry history (i.e. the TFS 2000™ stoichiometry profile) dominates the NO_x formation and reduction processes at these levels of global air staging.

Finally, several configurations which applied integrated vertical and horizontal staging techniques as a means of “optimizing” the stoichiometry of combustion within the main windbox were evaluated. Integrated vertical and horizontally staged firing systems were extensively evaluated using CFD modeling prior to the BSF test. In contrast to their independent performance, Figure 11 shows that when suitably combined, an integrated vertical and horizontal staging strategy offers a small, but consistent improvement to the NO_x emissions performance of the optimized TFS 2000™ system. At a NO_x emission level of 0.11 pounds/ MMBtu, the “best” integrated system (shown on Figure 11 as “Integrated Config. 6”) produced a greater than 10% reduction in NO_x over the previously optimized TFS 2000™ system. Carbon loss results (not shown) were also similar for the two firing systems.

Summary

Chemical kinetic modeling, computational fluid dynamics (CFD) and small scale combustion testing in ABB Power Plant Laboratories’ Fundamental Scale Burner Facility (FSBF) have demonstrated that, in addition to global stoichiometry, the build-up of the stoichiometry within the main windbox zone influences the overall NO_x

formation for a given firing system configuration. By controlling and optimizing the mixing of the fuel and air in the main windbox zone, improved NO_x performance can be achieved.

During the pilot scale NO_x control subsystem testing in the ABB Power Plant Laboratories' Boiler Simulation Facility (BSF), in-furnace NO_x reductions of 75%, compared to the baseline, unstaged firing system, were demonstrated for an "optimized" TFS 2000™ firing system on the test, Viking coal. Additional enhancements to this system in the form of integrated vertical and horizontal staging of the coal and air within the main windbox region, identified through the use of CFD modeling, demonstrated the potential to produce an additional 10% reduction in NO_x emissions over the previously optimized TFS 2000™ system. During the BSF testing, a test period "best" NO_x emissions level of 0.11 pounds/ MMBtu was achieved with integrated vertical and horizontal staging superimposed on a TFS 2000™ globally staged firing system.

Additional pilot scale testing of potential NO_x control subsystems in the BSF is currently planned for early 1996 under this project. This testing will serve to further confirm the performance of the integrated vertical and horizontal staging technique, focusing on the repeatability of the present test results, while generating design information for this and other, promising, firing system concepts for eventual full scale utility boiler application.

Acknowledgements

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	AS RECEIVED	MOISTURE FREE	MOISTURE & ASH FREE	PARTICLE MESH SIZE	SIZE % RETAINED
PROXIMATE ANAL., WT. %					
MOISTURE (TOTAL)	3.0			+ 50	trace
VOLATILE MATTER	33.3	34.4	36.3	+ 70	0.2
FIXED CARBON (DIFF.)	58.6	60.4	63.7	+100	0.5
ASH	5.1	5.2		+140	2.6
TOTAL	100.0	100.0	100.0	+200	6.7
				-200	90.1
HHV, BTU/LB	13,288	13,699	14,455		
LB ASH/ MMBTU	3.8				
ULTIMATE ANAL., WT. %					
MOISTURE (TOTAL)	3.0				
HYDROGEN	4.0	4.1	4.3		
CARBON	75.2	77.6	81.8		
SULFUR	0.7	0.8	0.8		
NITROGEN	1.8	1.8	1.9		
OXYGEN (DIFF)	10.2	10.5	11.2		
ASH	5.1	5.2			
TOTAL	100.0	100.0	100.0		

Table 2 - REND LAKE COAL ANALYSIS

	AS RECEIVED	MOISTURE FREE	MOISTURE & ASH FREE	PARTICLE MESH SIZE	SIZE % RETAINED
PROXIMATE ANAL., WT. %					
MOISTURE (TOTAL)	4.1			+ 50	trace
VOLATILE MATTER	35.2	36.7	40.7	+ 70	0.2
FIXED CARBON (DIFF.)	51.3	53.5	59.3	+100	0.7
ASH	9.4	9.8		+140	2.7
TOTAL	100.0	100.0	100.0	+200	6.0
				-200	90.3
HHV, BTU/LB	12,572	13,109	14,529		
LB ASH/ MMBTU	7.5				
ULTIMATE ANAL., WT. %					
MOISTURE (TOTAL)	4.1				
HYDROGEN	5.4	5.6	6.2		
CARBON	68.9	71.9	79.6		
SULFUR	2.6	2.7	3.0		
NITROGEN	1.6	1.6	1.8		
OXYGEN (DIFF)	8.0	8.4	9.4		
ASH	9.4	9.8			
TOTAL	100.0	100.0	100.0		

Table 3 - VIKING COAL ANALYSIS

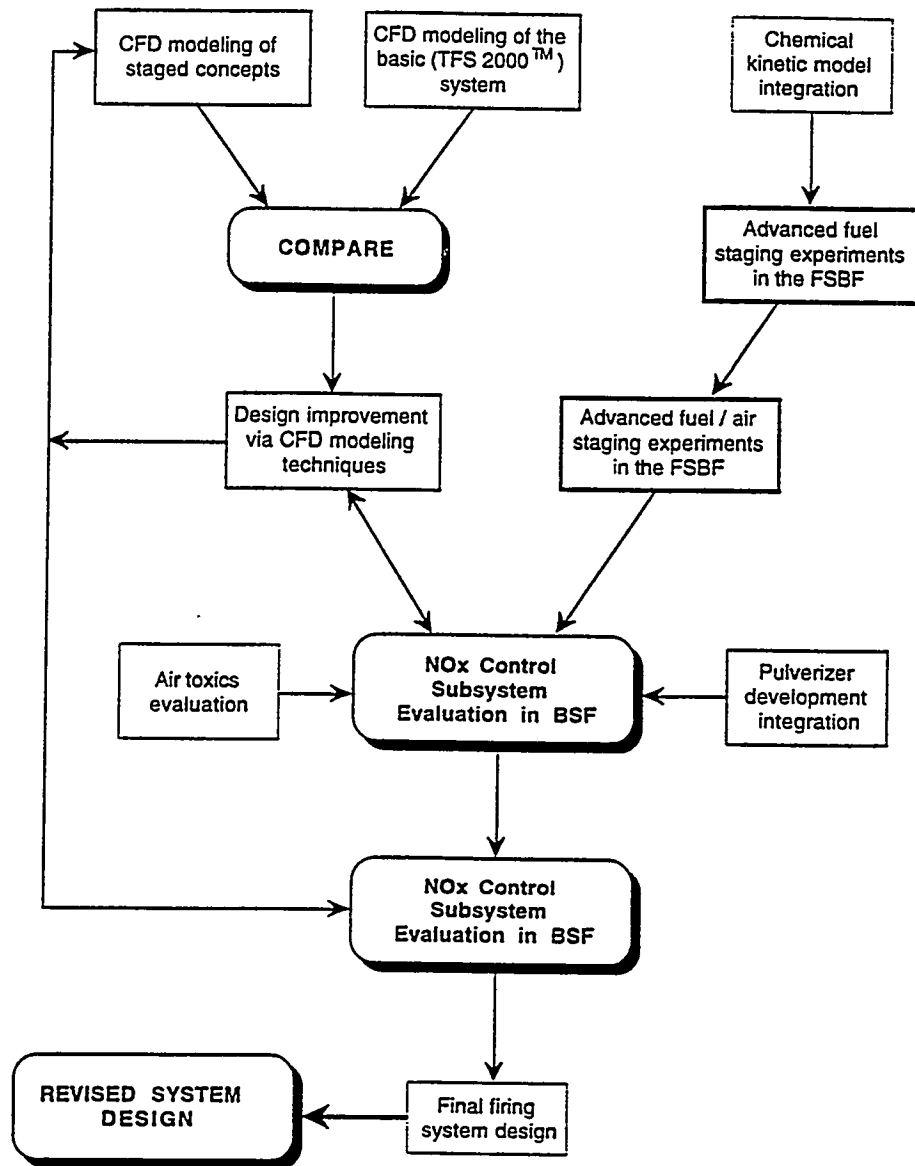


Figure 1 - LEBS NO_x Control Subsystem Work Flow Chart

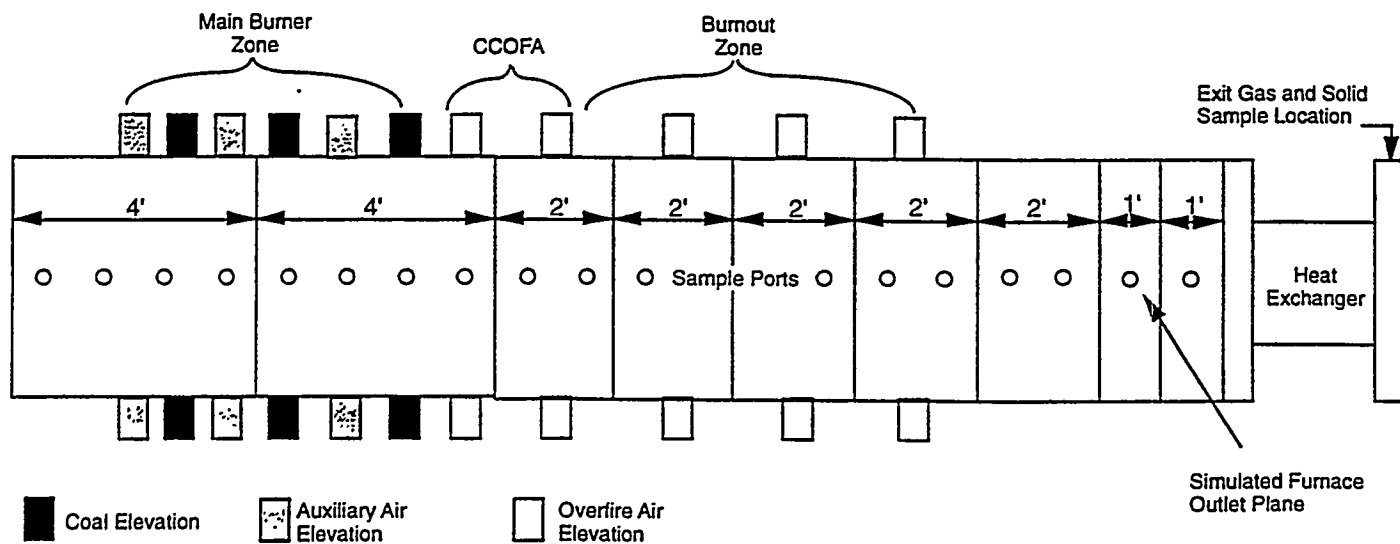


Figure 2 - Schematic of Fundamental Scale Burner Facility

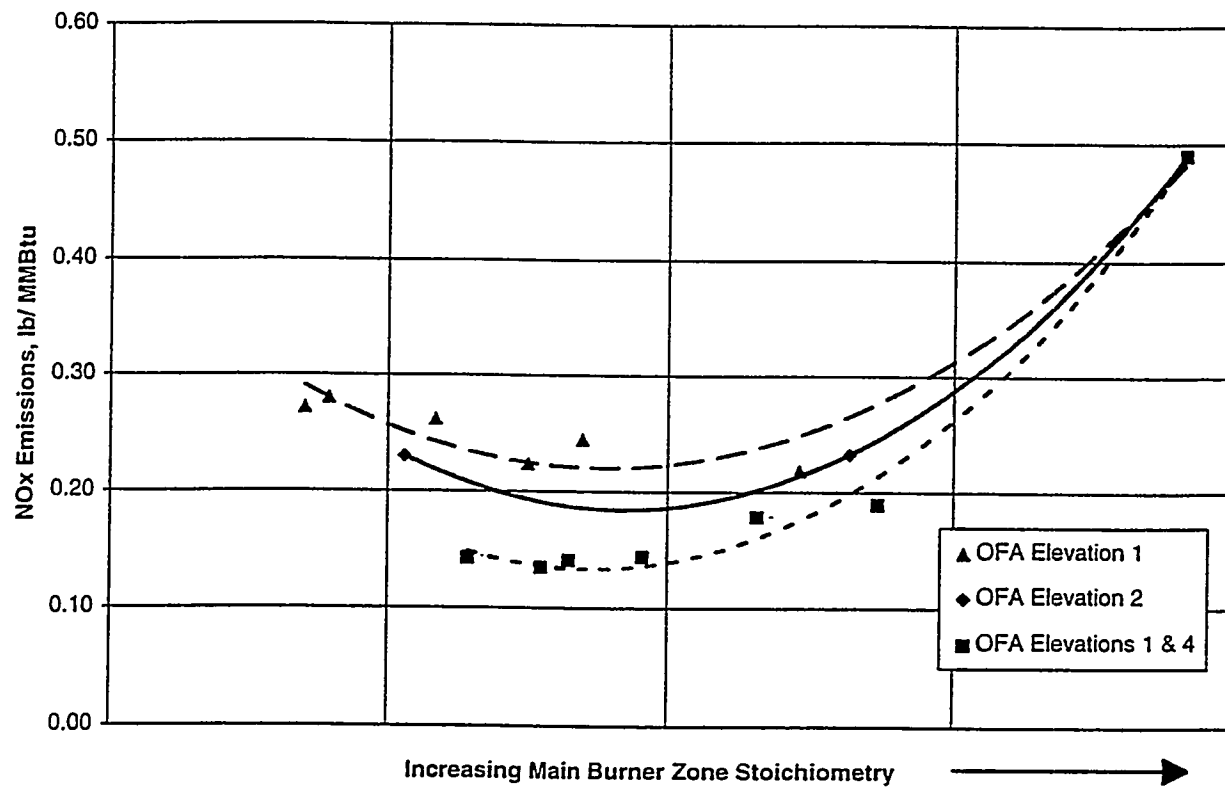


Figure 3 - NOx vs. Main Burner Zone Stoichiometry

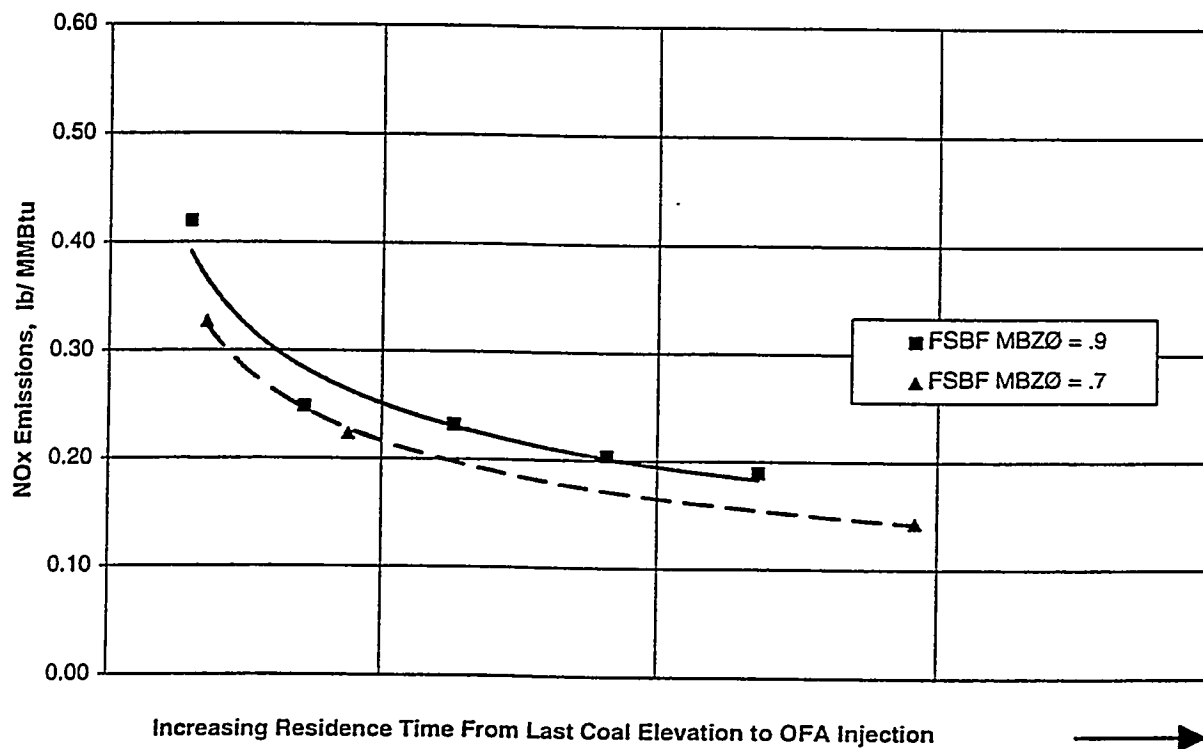


Figure 4 - Effect of Residence Time on Flue NOx

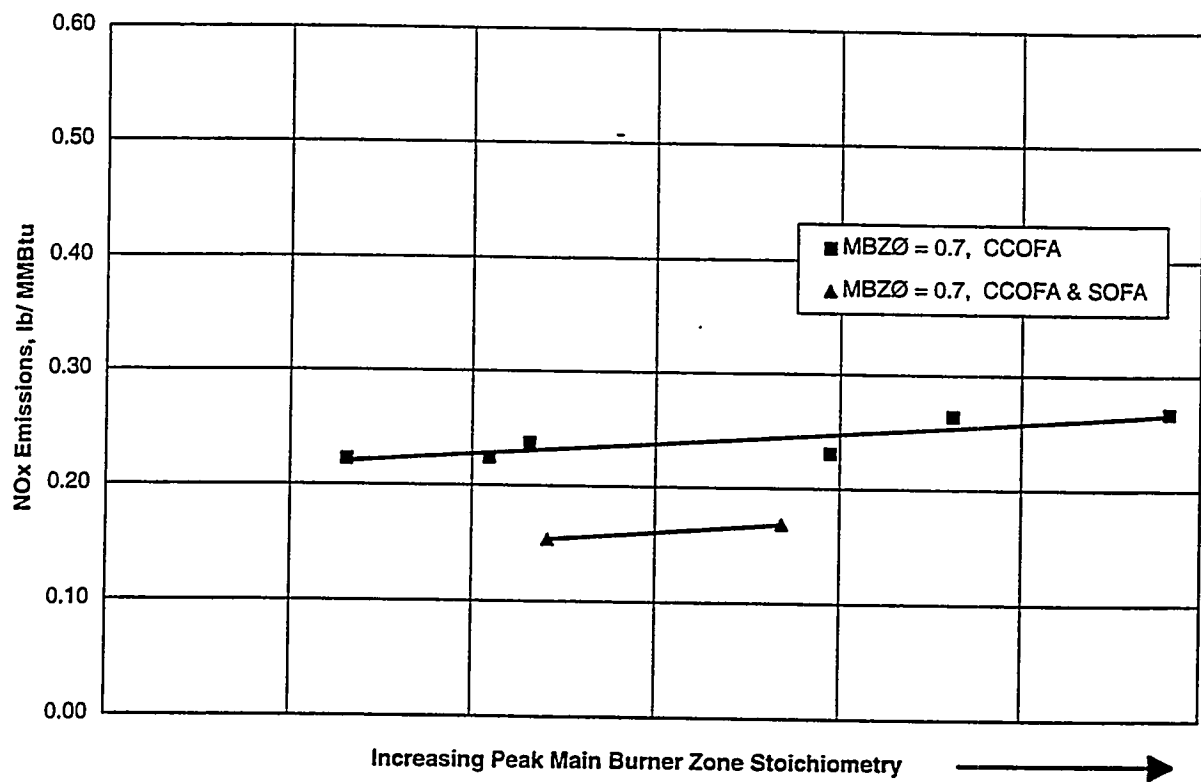


Figure 5 - Outlet NOx vs Maximum Bulk Windbox Stoichiometry

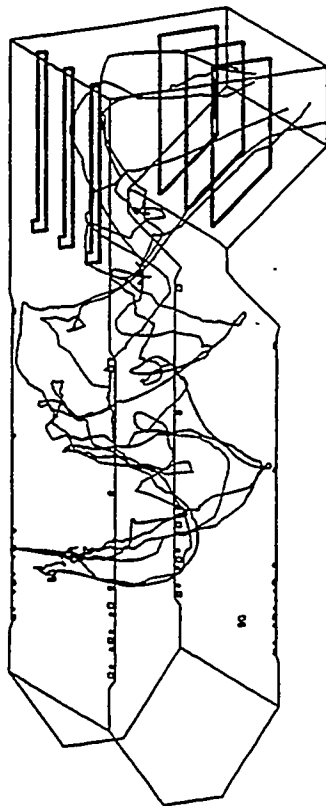


Figure 6 - Typical Coal Particle Trajectories

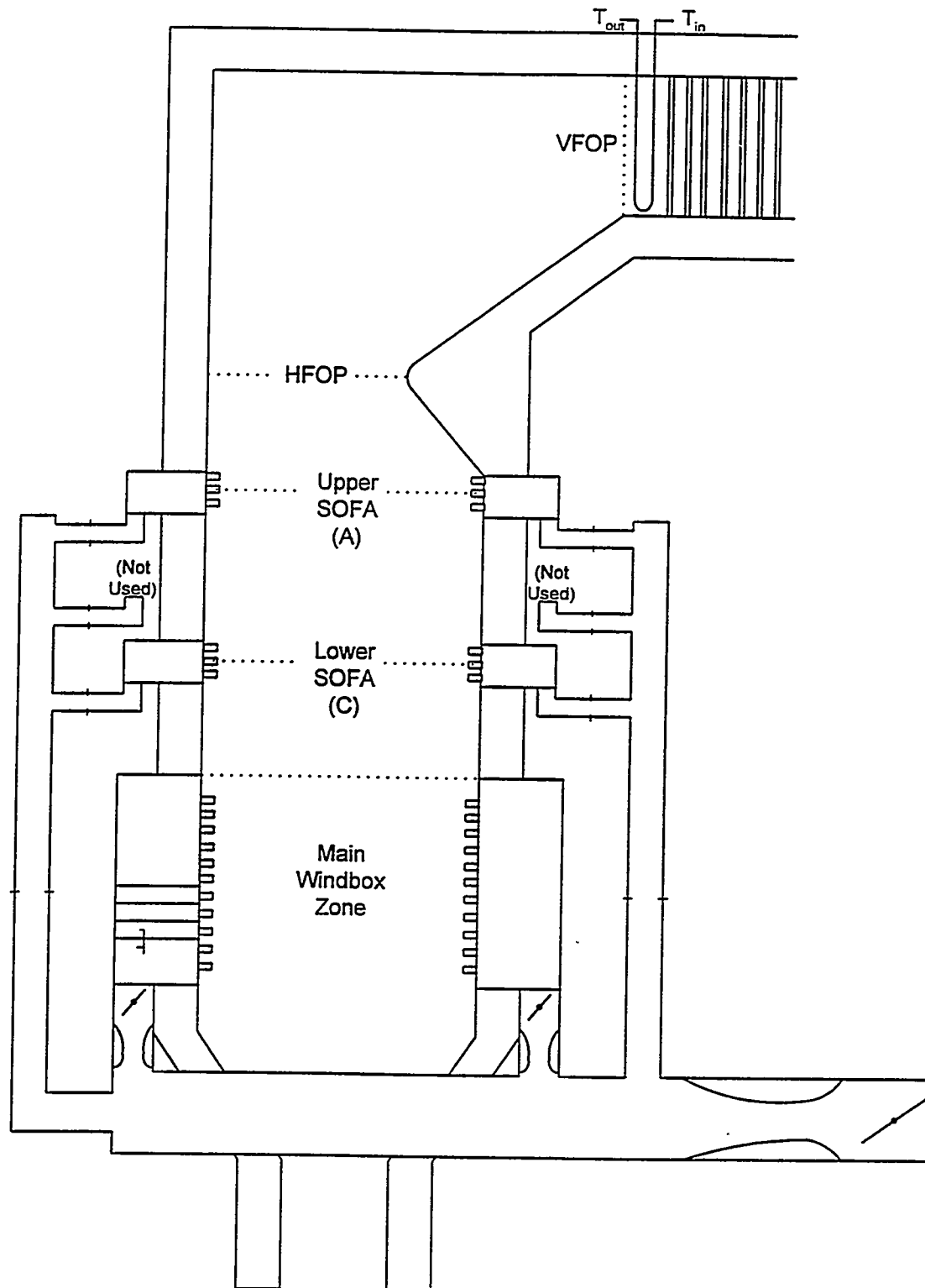


Figure 7 - ABB PPL's Boiler Simulation Facility (BSF)

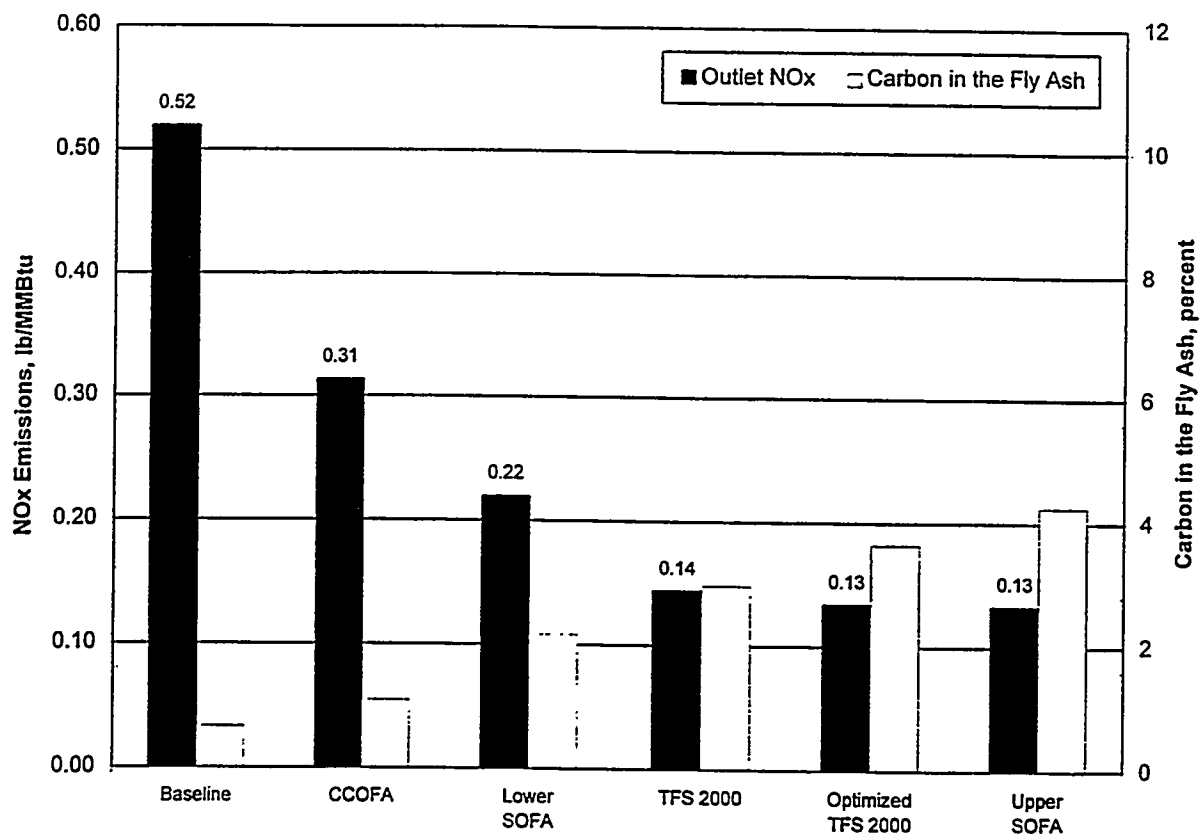


Figure 8 - Outlet NOx and Carbon in the Fly Ash versus Over Fire Air Configuration

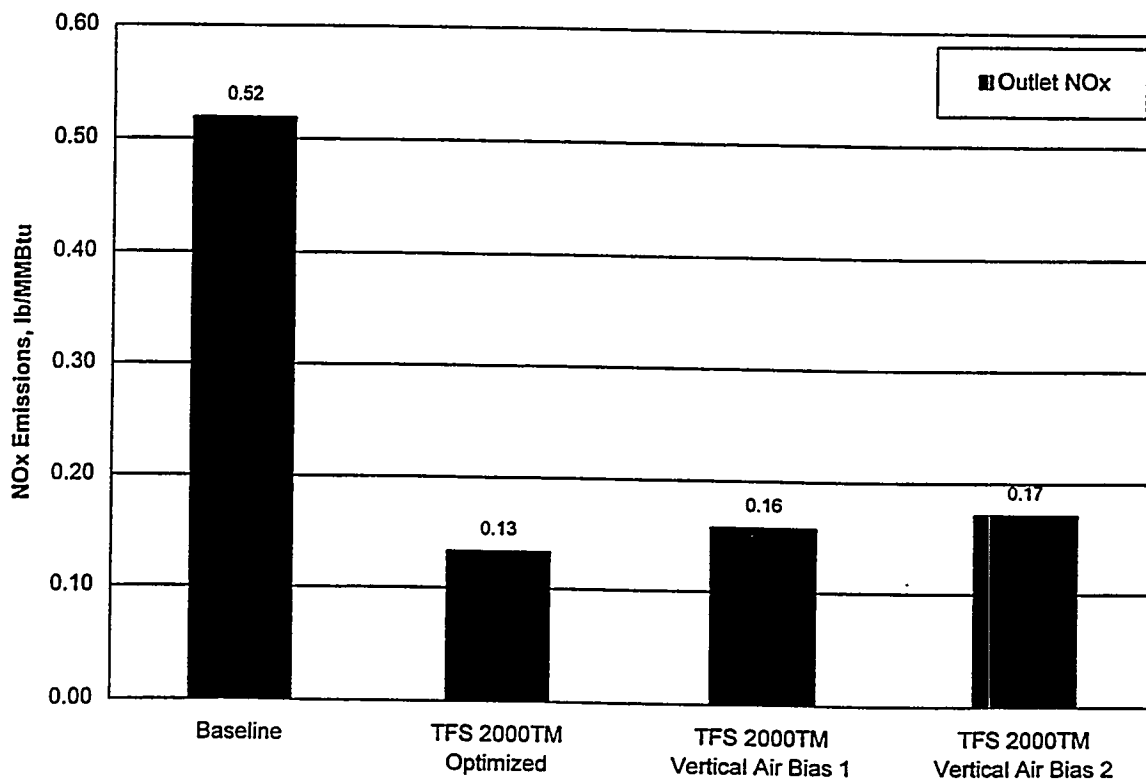


Figure 9 - Outlet NOx versus Main Windbox Vertical Air Staging

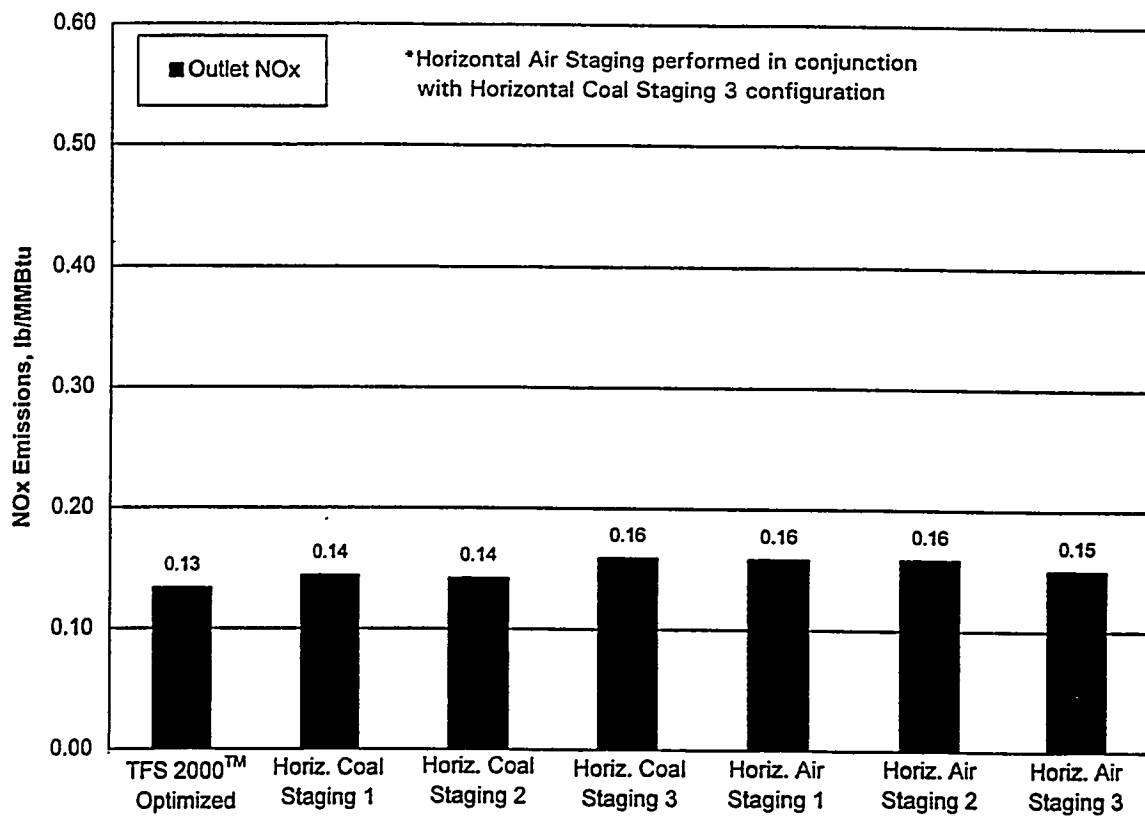


Figure 10 - Outlet NOx versus Main Windbox Horizontal Coal and Air Staging*

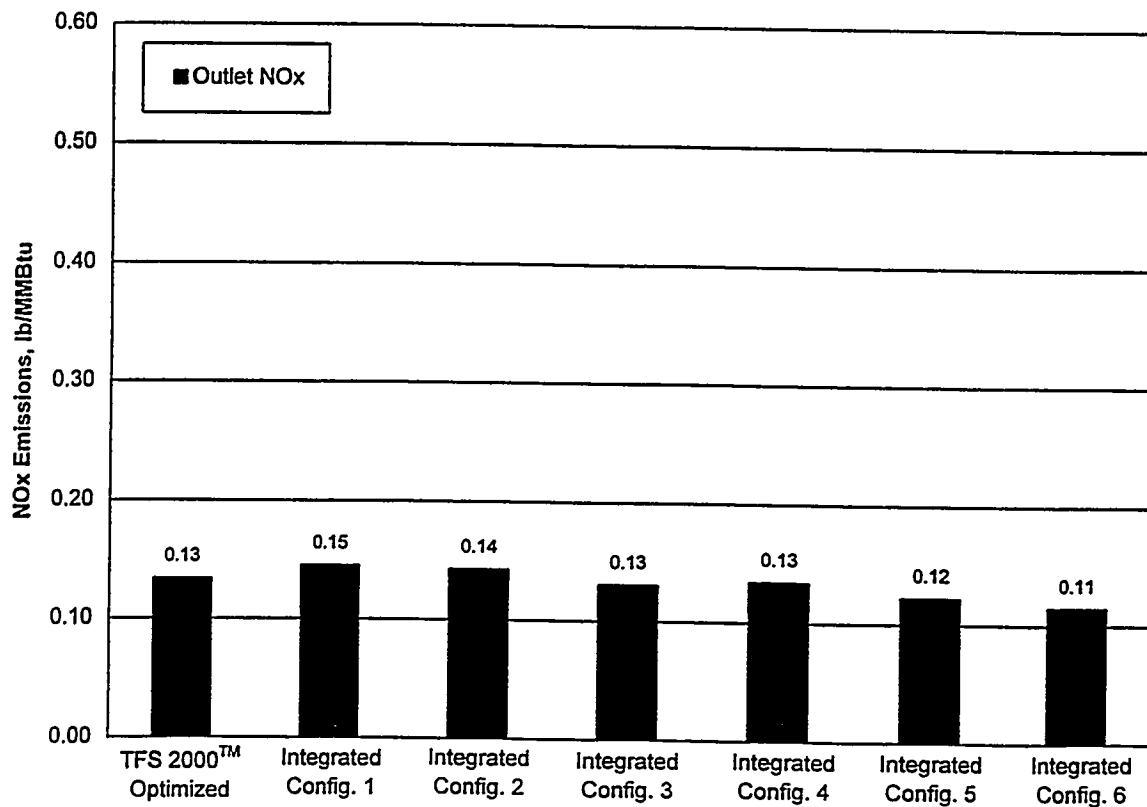


Figure 11 - Outlet NOx versus Integrated Main Windbox Vertical and Horizontal Staging

APPENDIX E - 36 pages

CORROSION AND DEPOSITION IN REDUCTING ENVIRONMENTS

(ABB PPL Project Nos. 96999210, 211)

Introduction

Staged coal firing provides a viable technology to meet the stringent requirements on NO_x emissions. However, because of the substoichiometric conditions during staged firing, relatively high concentrations of total reduced sulfur (TRS) species and unburned carbon can exist at boiler waterwalls, resulting in conditions that can be conducive to corrosion attack.

Limited data are available in the open literature regarding materials selection for low-NO_x staged firing applications. Bench-scale laboratory experiments aimed at simulating low-NO_x firing environments have been conducted by various investigators on carbon and low alloy steels at 500 °C with gas compositions calculated assuming the combustion of coals at equilibrium state with substoichiometric amounts of air. Concentrations of H₂S ranging from 0.3 to 2.0% by volume (depending on the substoichiometric fuel/air ratio and the sulfur content of the coal) were used in these experiments. The results from these experiments showed the metal recession rates increased with increasing testing temperature, exposure time and H₂S partial pressure. However, these results generally represent a worst case scenario. The H₂S concentrations utilized in these studies were significantly higher than those measured in units with low-NO_x staged firing (EPRI report CS-6339, 1989, and Plumley, et al,

Table 1 Corrosion Rates for Low Alloy Steels Under Equilibrium

Reducing Gas Compositions

Source	H ₂ S (vol %)	Temperature (°C)	Corrosion Rate (µm /year)	Conditions
Other	0.5	482	2032	Thermal cycling, 1000 hours SA-210
Other	2.0	482	1041	Isothermal 4000 hours SA-210
ABB-CE	0.3	482	1727	Isothermal 160 hours SA-210

1977). In addition, most of the data shown in Table 1 were extrapolated as a linear function of time, giving wastage rate predictions that are too conservative for real applications. More appropriate laboratory tests are needed to develop predictive tools for corrosion under substoichiometric firing conditions, including micro-climate effects under carbonaceous deposits.

To develop a better understanding of the effect of low-NO_x staged combustion on materials attack under more realistic local reducing conditions at waterwalls, ABB Power Plant Laboratories conducted parametric bench-scale corrosion studies and corrosion probe exposures during combustion tests at 50 MMBtu/hr firing rate in ABB CE's Boiler Simulation Facility (BSF). The effects of reduced sulfur forms and concentrations, with and without carbonaceous deposits of various sulfur contents, were systematically evaluated. Short term exposures under heat transfer conditions were also conducted in bench-scale and in the BSF. The information obtained from this task is to be integrated into the LEBS design, to aid in selection of materials and/or firing arrangements to provide reasonable waterwall protection under staged low-NO_x firing conditions.

Technical Approach

Isothermal bench-scale tests were conducted at 500 °C with test pieces of SA-213 grade T-11 steel, chromized T-11, and 310 stainless steel for up to 1500 hr in a gaseous environment containing 400-1600 ppm H₂S, 13% CO, 7% CO₂, 2% H₂, balance N₂. These gas compositions were selected based on measurements obtained from field units while firing under staged low-NO_x conditions. Complementary tests were conducted with a reducing gas containing a comparable sulfur content in terms of COS and CS₂ with a shorter exposure of 500 hr. A broader selection of materials, Table 2 were also tested embedded in coals or carbonaceous deposits with various sulfur content under a slightly oxidizing gaseous stream containing 600 to 1400 ppm

SO₂ and 600 ppm to 4% O₂ in N₂ at 500 °C for periods of up to 800 hr. The latter experiments were conducted at ABB Heidelberg Research Center.

After exposure, the test pieces were analyzed metallographically and kinetic data were obtained from descaled samples using an inhibited HCl solution. The corrosion susceptibility for chromized T-11 material was determined from metallographic cross-sections. The corrosion products were characterized using scanning electron microscopy (SEM) with an electron dispersive spectrometry X-ray analyzer (EDAX) attachment.

Metallographic evaluations were also conducted on corrosion probes exposed to various low-NO_x firing configurations in the BSF. The corrosion probes were made of samples of T-11 and/or T-11 chromized tubing. After exposure, the probes were coated with an acrylic spray to retain deposits and corrosion scales on the probe surface. Sections of the probe were cut and mounted in a polyester matrix resin (Si and Cl free), polished using conventional procedures and then etched with a 2 or 5% nital solution to reveal base metal microstructural features. Chromized samples were also etched with Murakami solution to reveal the structure of the coating. The corrosion and deposition products were analyzed in a similar fashion to that for test pieces from the bench scale laboratory tests.

Table 2 Materials Tested Under Microclimate Conditions with
Carbonaceous Deposits

Material	Composition									
	Cr	Ni	Nb	Mo	Al	Si	C	Mn	Fe	Other
ST37						0.55	0.17	1.6	bal.	
CS Chrom										
T-11	1.25			0.5					bal.	
T-11 Chrom										
T-22	2.5			1					bal.	
T-91	8.7	0.07	0.07	0.93		0.47	0.1	0.5	bal.	Y:0.2
ST12T	12	0.5	0.05	1		0.5	0.25	0.5	bal.	Y:0.3
HCM-12	12			1						
321SS	18	10.5				<1	<0.1	<2	bal.	Ti:<0. 8
316SS	17.5	12		2.25		<1	<0.1	<2	bal.	Ti:<0. 8
IN617	22	bal.		9	1.1	1	0.1	1		Co: 12
IN625	22	bal.	3.5	9	0.4	0.5	0.1	0.5		Co:1

Additional testing included the measurement of total reduced sulfur species and CO at various elevations and locations in the BSF unit to assess the relationship between these species as possible indicators for waterwall wastage susceptibility. Bench-scale experiments under heat transfer conditions were also conducted. The test pieces from these experiments were analyzed and the results were compared with those from isothermal corrosion tests conducted with gases of similar composition.

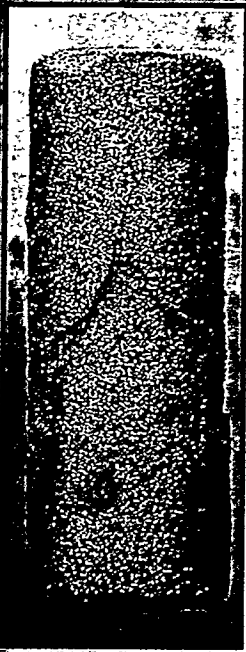
Summary of Experimental Data and Analysis of Results

Isothermal Bench-Scale Testing

Effect of reduced sulfur gaseous species: Figure 1 shows a series of micrographs that provide an indication of the susceptibility of the various materials to corrosive attack after 1500 hr of exposure to a reducing gas mixture containing 1000 ppm H₂S at 500 °C. The T-11 material showed the greatest susceptibility to high-temperature sulfidation followed by 310 SS while chromized T-11 suffered the least attack. The corrosion product on T-11 was an iron sulfide of the pyrrhotite stoichiometry, similar to the outer scale formed on the 310 SS.

The 310 SS also showed internal sulfidation with the formation of a phase rich in Cr and Mn, with some Fe and S. Wavelength dispersive spectrographic analysis (WDS)

A: SA-213 grade T-11 Steel



B: 810SS

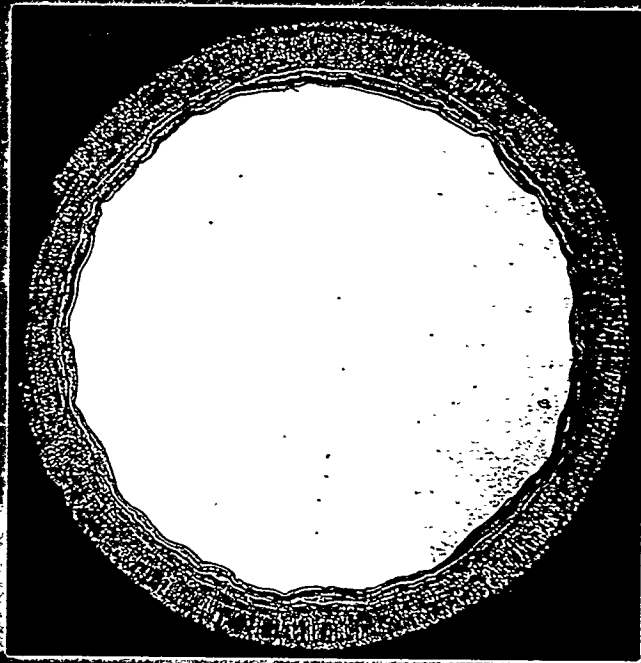
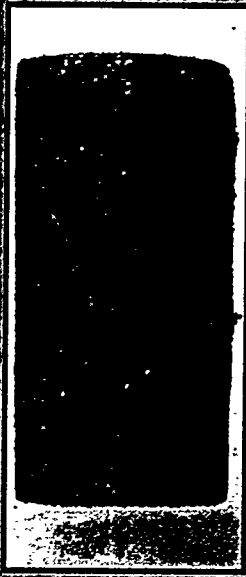


Figure 11 Optical micrographs from capsules exposed for 1500 hr at 500°C to gaseous stream containing 1000 ppm H₂S. (Micrographs reduced 15% for editing purposes)

revealed the additional presence of oxygen in this phase suggesting a mixture of (Cr,Mn)-oxide spinel and (Cr,Fe,Mn)-sulfide. The internal oxidation front was irregular with a maximum penetration of about 40 μm .

Figure 2 shows the weight loss as a function of exposure time for both T-11 and 310 SS. Evaluation of the data for T-11 indicates sublinear kinetics with an exponential time dependence of about 0.8 which is in agreement with the results reported by other researchers (Perkins, 1983 and John, 1993) for this type of material under testing conditions simulating coal gasification environments with appreciably higher H_2S contents, e.g 6000 to 17000 ppmv.

Evaluation of the data for the 310 SS material gave an exponential time dependence of 0.2, but since this material is normally used at higher temperatures, no comparable published kinetic data could be obtained. References indicating a loss of 50 $\mu\text{m}/\text{y}$ in a simulated coal gasification environment at 480 $^{\circ}\text{C}$ (Kung, et al, 1993) are broadly consistent with the present results.

In order to develop the capability to predict corrosion rates for low alloy steels in combustion gases containing H_2S , the data from current and previous bench scale tests were statistically evaluated to determine a correlation between metal recession, time and H_2S content. Multiple variable regression analysis considering weight loss as the

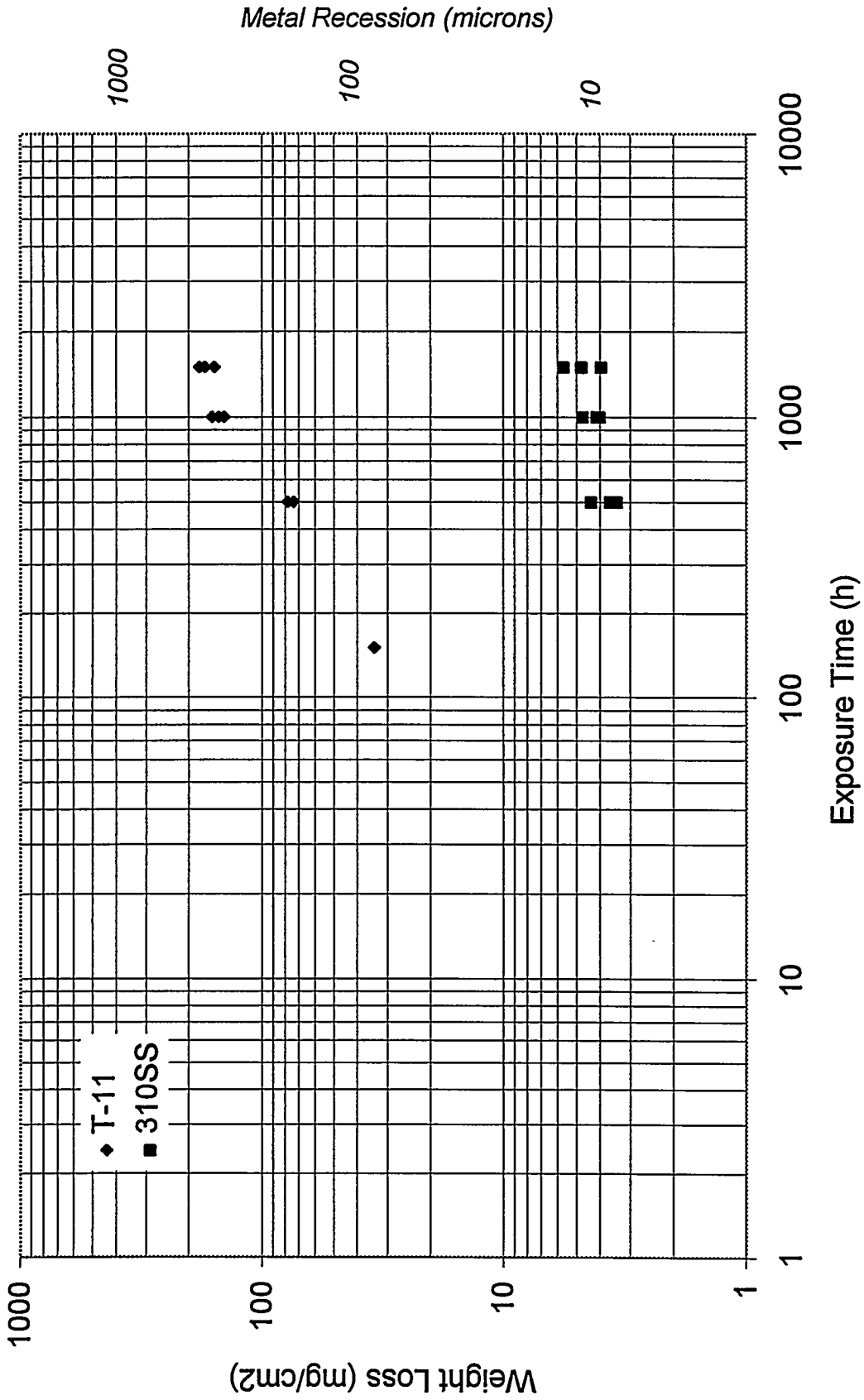


Figure 2 - Weight change for SA-213 Grade T-11 steel and 310SS exposed to low NOx waterwall environment containing 1000 V ppm H₂S at 500 °C

dependent variable and H₂S content and time as the independent variables at 500 °C gave the following relation,

$$\text{WEIGHT LOSS [mg/cm}^2\text{]} = 7.74 \times 10^{-3} \{\text{H}_2\text{S}\}^{0.54} \{\text{time}\}^{0.86} \quad [1]$$

where the H₂S content and time are in ppmv and in hr, with a regression factor of 0.96. The correlation was tested against the data collected using a gas stream containing 1000 ppmv H₂S and plotted in Figure 3 confirming an excellent agreement. Figure 4 gives the predicted recession rates expected as a function of the H₂S content at 500 °C using the preliminary model given by Equation [1].

It should be noted that the above correlations are based on relatively short term exposure experiments. Long term exposure experiments for various H₂S concentrations are needed to validate the results.

Figure 5 shows the SEM micrographs from chromized T-11 exposed for times up to 1500 hr at 500 °C in a gaseous stream containing 1000 ppm H₂S. The 20 μm scale was composed of chromium-sulfide as evidenced by the corresponding EDS spectra and was formed on top of the outer chromium-carbide layer that resulted from the chromizing process. In terms of corrosion kinetics, the outer chromium-carbide layer delays the onset of appreciable attack providing a diffusion barrier preventing the

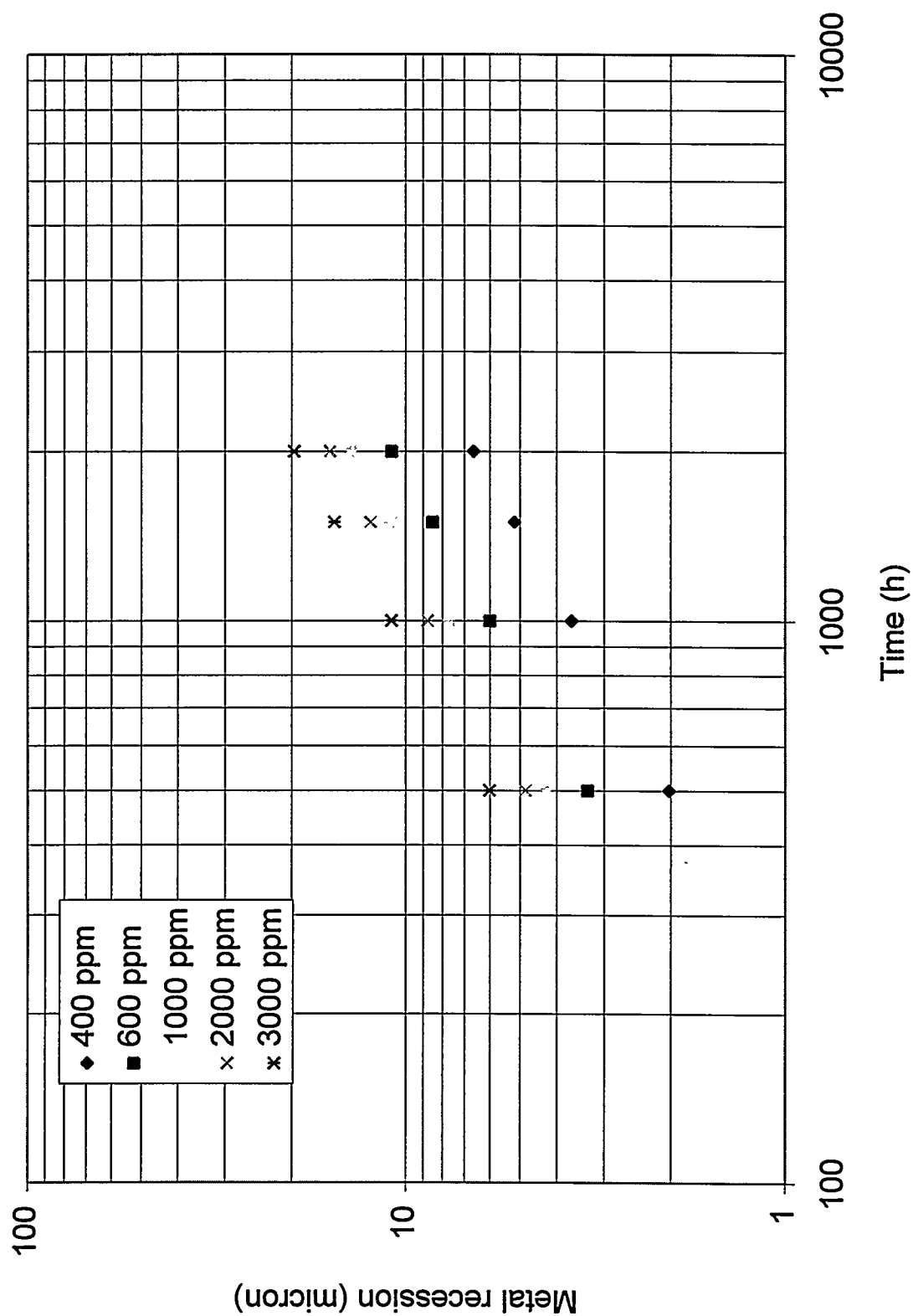


Figure 4 - Calculated metal recession for T-11 material as a function of H₂S content in the gas and time at 500 °C

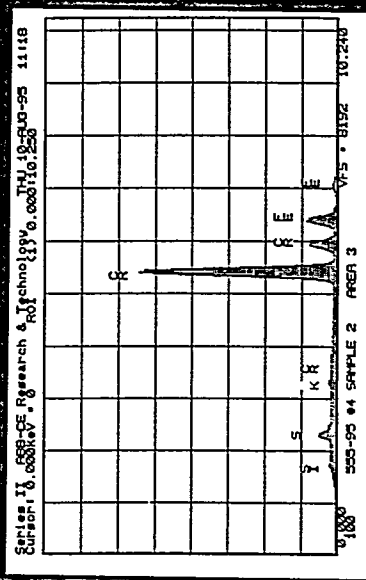
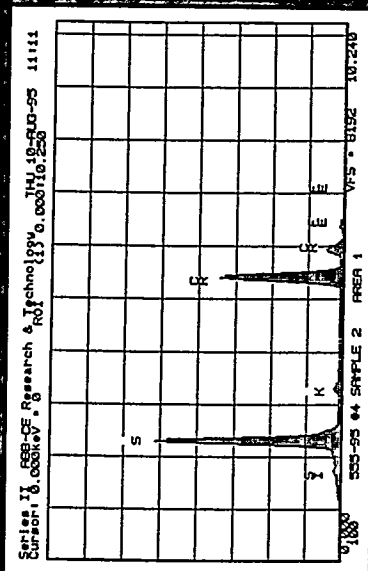
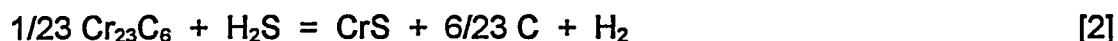


Figure 1. SEM micrographs and EDS spectra from the corrosion product formed on a chromized Ti steel sample after exposure for 1500 h at 500°C to simulate reducing gaseous stream containing 1000 ppm H₂S. (Micrographs reduced 80% for editing purposes).

ingress of aggressive species. Thermodynamically, Cr-carbides are susceptible to sulfidation in H₂S containing gaseous environments by the following displacement reaction:



However, the kinetics of this process will be limited by the ability of the underlying diffusion layer to accommodate the released C atoms. During the initial stages of sulfidation, the C atoms could evolve as a gaseous species, CO, but once the sulfide scale is established at the surface of the chromium-carbide layer, further attack will be limited by the inward diffusion of C. The absence of iron in the sulfide scale suggest that the chromium-carbide layer does not allow appreciable diffusion of Fe cations as chromium-oxide layers do, thus delaying the onset of sulfidation. Below the surface carbide layer, the diffusion layer contains as much as 60 wt% Cr providing adequate sulfidation resistance in the event that mechanical damage or fly ash impingement results in erosion of the surface carbide layer.

The kinetics of sulfidation in reducing environments containing reduced sulfur species other than H₂S was also evaluated by conducting short term exposures, up to 640 hr, with test pieces of T-11 and chromized T-11 material at 500 °C under gaseous streams containing COS and CS₂. Figure 6 shows the optical micrographs depicting the appearance of the samples after exposure. The bare T-11 material suffered from high-

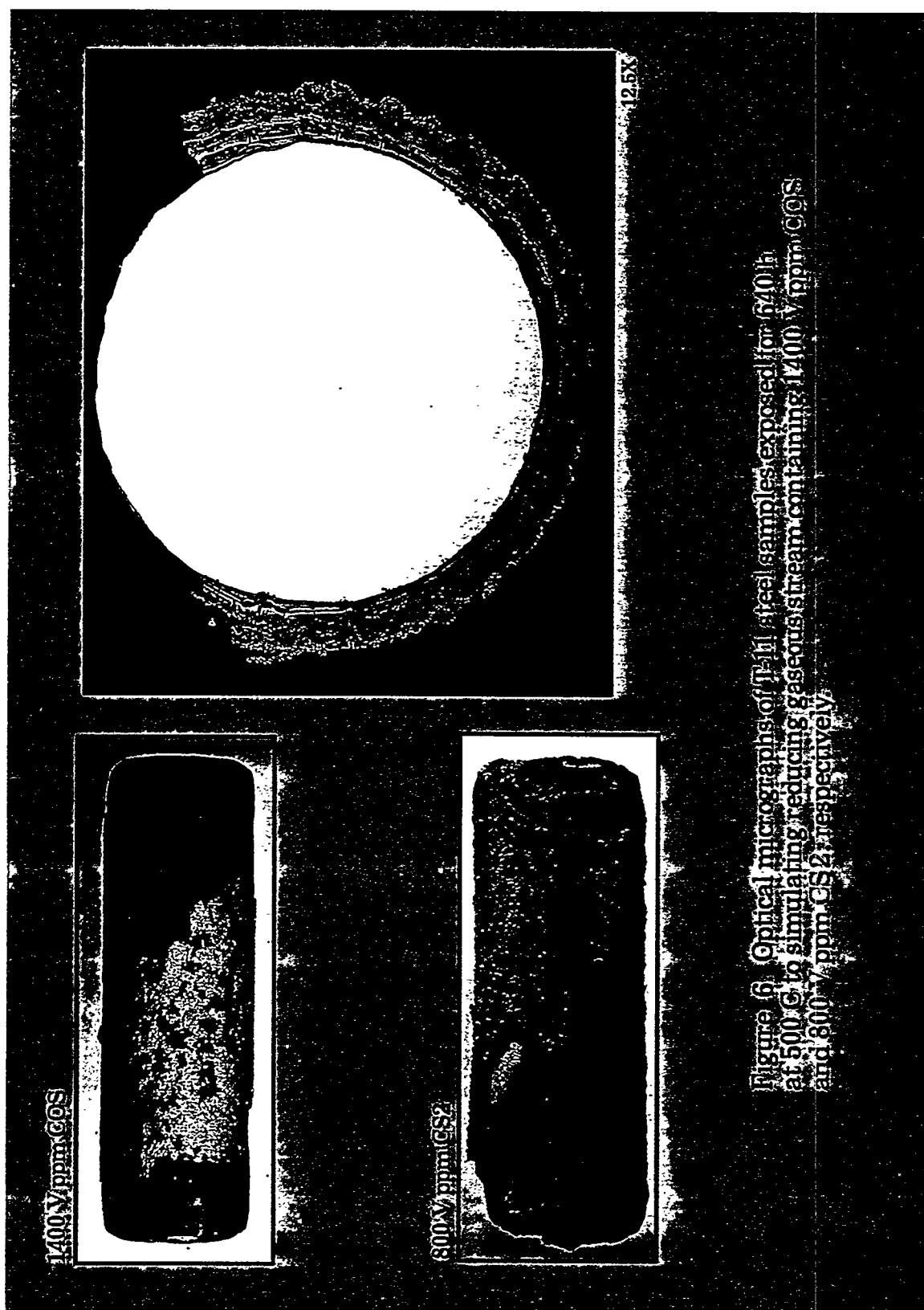


Figure 6. Optical micrographs of T-11 steel samples exposed for 640 h at 500 C to simulating reducing gaseous stream containing 1400 V ppm COS and 800 V ppm COS, respectively.

temperature sulfidation with the formation of pyrrhotite, Fe_{1-x}S , similar to that obtained when using H_2S containing gases. The chromized samples showed only minor attack with chromium-sulfide formation, and, as in the case of H_2S exposures, the surface chromium-carbide layer provided protection against accelerated sulfidation attack.

Figure 7 shows a comparison of the weight loss for T-11 material for the various reduced sulfur species at 500 °C after 640 hr. The data for 1600 ppmv H_2S were extrapolated from 500 to 640 hr using equation 1. The wastage rate was comparable for the H_2S and COS exposures but was about 60% greater for CS_2 . Carbon disulfide, CS_2 , was not reported during the parametric study but could still be present as part of the microclimate generated by the interaction of unburned carbon and various sulfur-containing species in the deposit formed on the waterwall.

Other alloying systems, such as iron-aluminides, thermally sprayed coatings and Al-Cr diffusion coatings, also have been evaluated in this program. The addition of aluminum to chromized or low alloy steels has improved their corrosion resistance to similar environments (Gesmundo, et al, 1994).

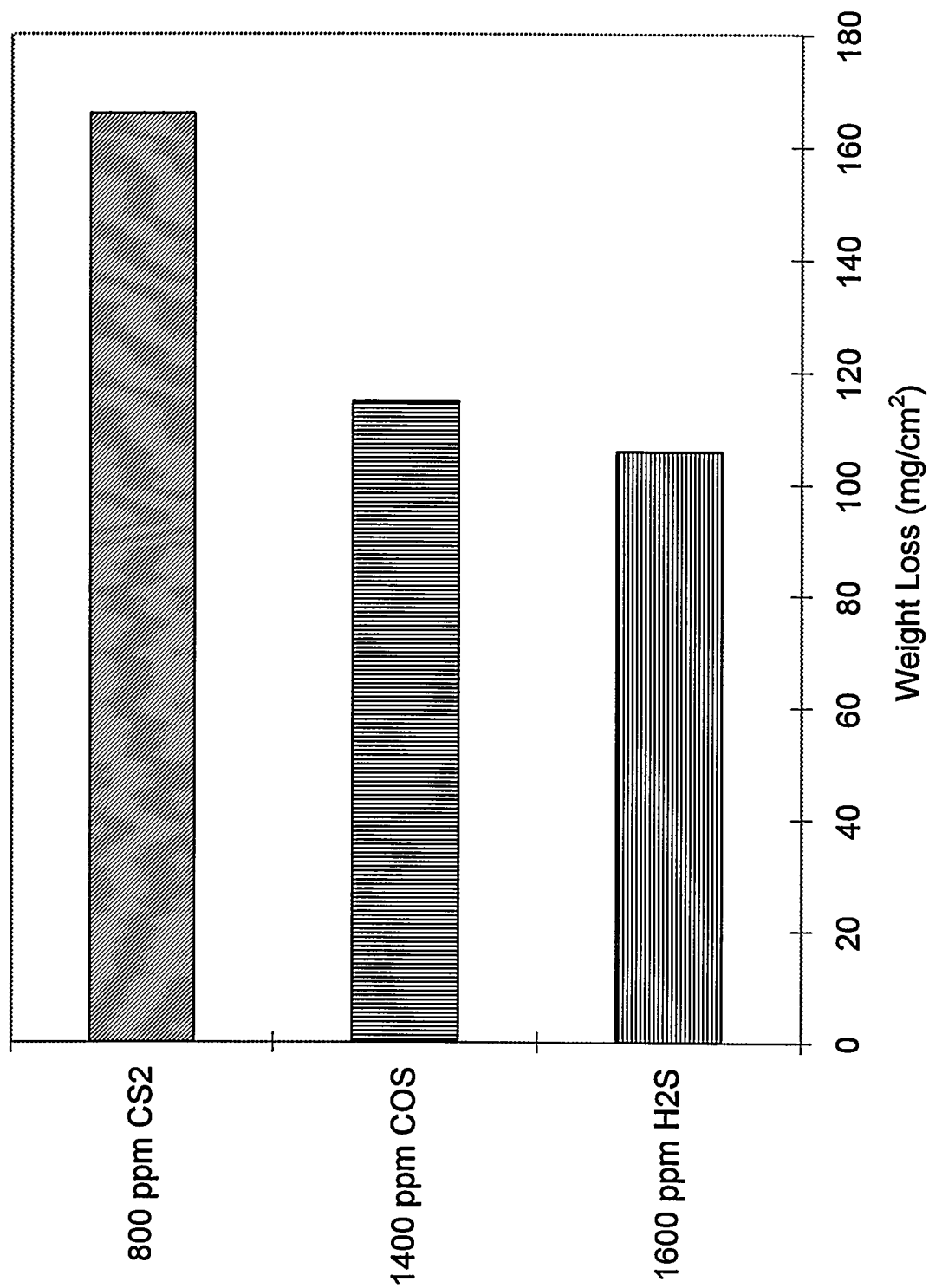


Figure 7 - Weight loss for T-11 material as a function of the sulfur carrier molecule in simulating low NOx waterwall gaseous environment after a 500 h exposure at 500 °C

Effect of carbonaceous deposits: During substoichiometric firing, deposits arriving at waterwalls can contain from 14 to 60 wt% unburned carbon. The presence of unburned carbon in the deposits generates a micro environment adjacent to the waterwalls that is potentially sulfidizing as suggested from thermodynamic calculations. At equilibrium state, carbon and otherwise oxidizing molecules, *i.e.* O₂, SO₂, are reduced to CO, COS and CS₂, with localized sulfur potentials high enough ($\log P_{S_2} \cong 1 \times 10^{-6}$ atm) to render Fe and Ni base alloys susceptible to high-temperature sulfidation.

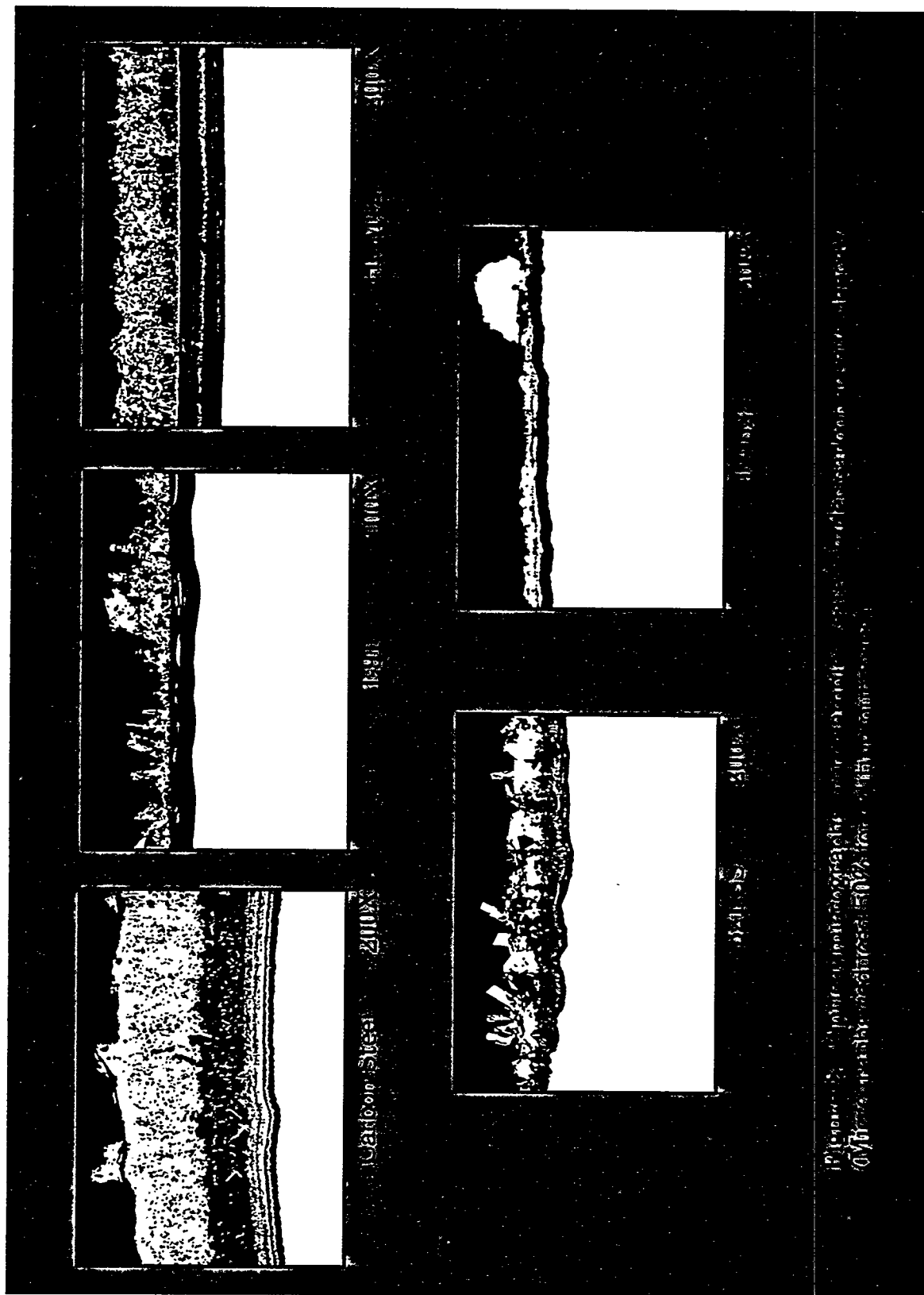
Table 3 gives the characteristics of the various sources of carbon used in this part of the program. Test pieces were embedded in the source of carbon and exposed under an O₂-SO₂-N₂ containing gas for up to 800 hr in the temperature range of 350 to 500 °C.

Table 3 Carbon Sources Used In The Testing Matrix for
Microclimate Studies

Quantity (wt%)	Eastern Bituminous Coal	Mid-western Bituminous Coal	Activated Carbon
Fixed Carbon	60.2	52.8	100
Moisture	2.9	14.6	na
Ash	6.8	9.7	na
Volatile matter	30.1	37.5	na
Total Sulfur	0.5	3.6	na
Pyritic S	nil	1.8	na
Sulfatic S	nil	0.03	na
Organic S	0.5	1.57	na

Figure 8 shows the optical micrographs depicting the extent of sulfidation for a selection of the alloys tested at 500 °C for 800 hr embedded in a mid-western bituminous coal (3.5% total sulfur) under a gas containing 600 ppmv O₂, 300 ppmv SO₂, and the balance N₂. Figure 9 provides a bar chart of the maximum penetration. The outer corrosion product was an iron sulfide for the iron base alloys while nickel sulfide was the outer scale in nickel base alloys. The inner sulfidation front contained, in addition to iron or nickel, chromium and other alloying elements in the form of mixed sulfide spinels. As can be appreciated from Figure 9 the resistance to sulfidation increased with increasing Cr-content of the alloy.

Figure 10 and 11 show that the metal recession of T-11 material increased with increases in both sulfur content in the gas and in the carbon source at 500 °C after 500 hr exposures. The presence of unburned carbon at waterwalls increases the risk of metal wastage from high-temperature sulfidation because of a microclimate effect. The unburned carbon interacts with the oxidizing gaseous molecules, *e.g.*, O₂ and SO₂, to generate a local environment containing CO, COS and CS₂, rendering pyritic and sulfatic mineral compounds in the coal unstable, releasing additional sulfur to react with the major constituents of the alloy.



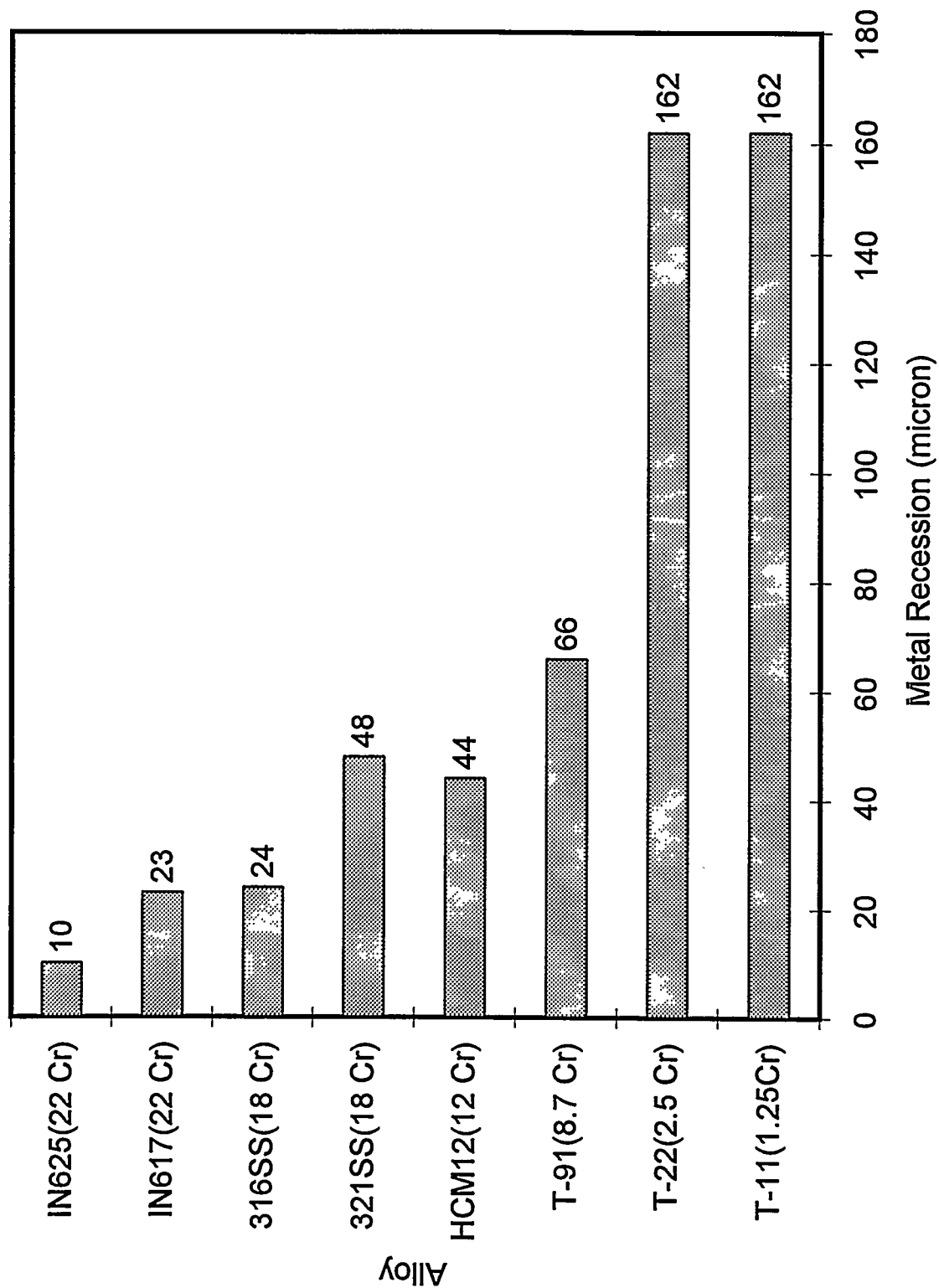


Figure 9 - Corrosion Susceptibility for samples embedded in a Bituminous coal with 3.5 wt% total sulfur after 800 h exposure in a 300 ppm SO₂-600 ppm O₂-N₂ gas at 500 °C.

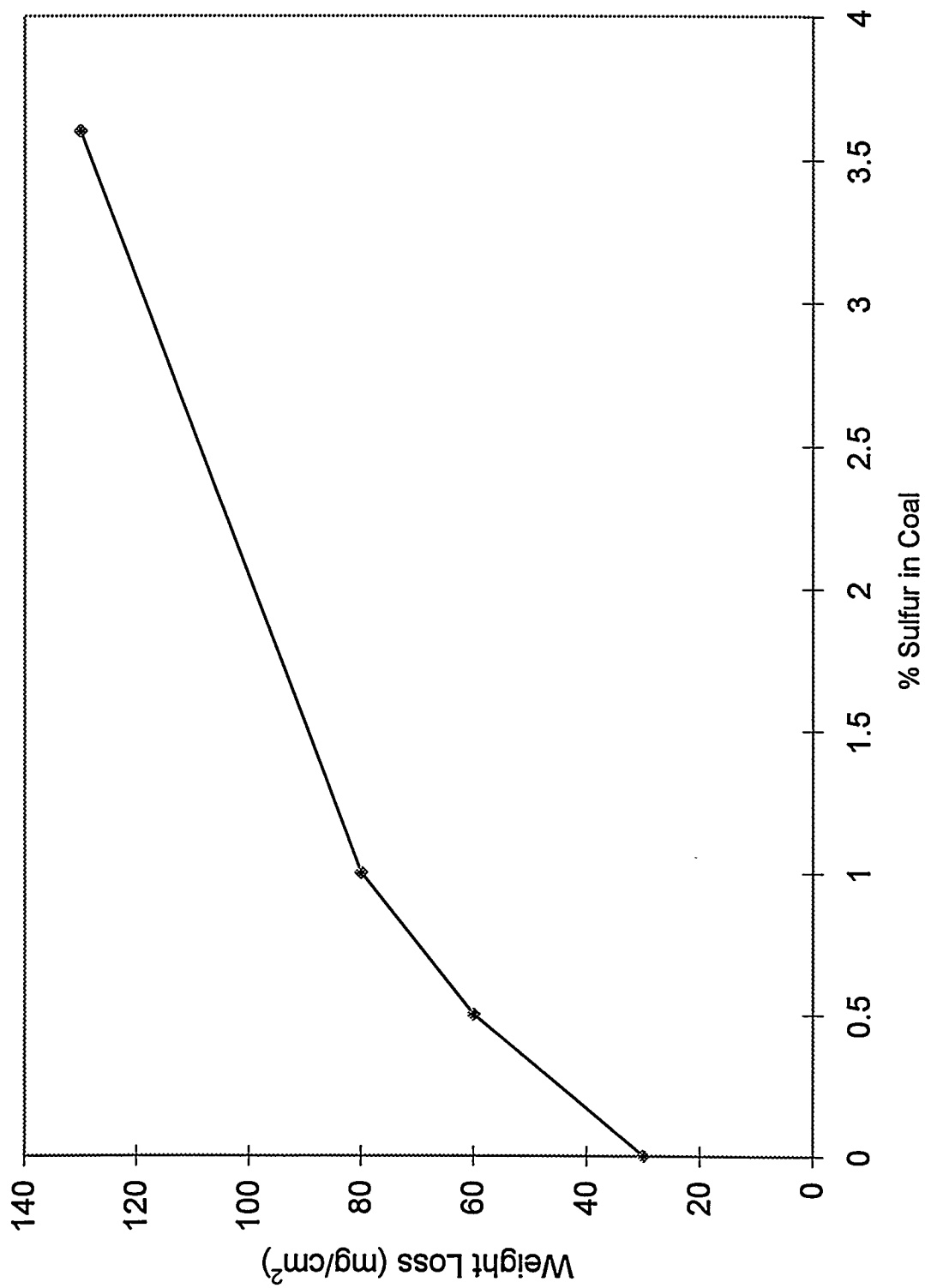


Figure 10 - Effect of coal sulfur content on metal recession for T-11 material at 500 °C

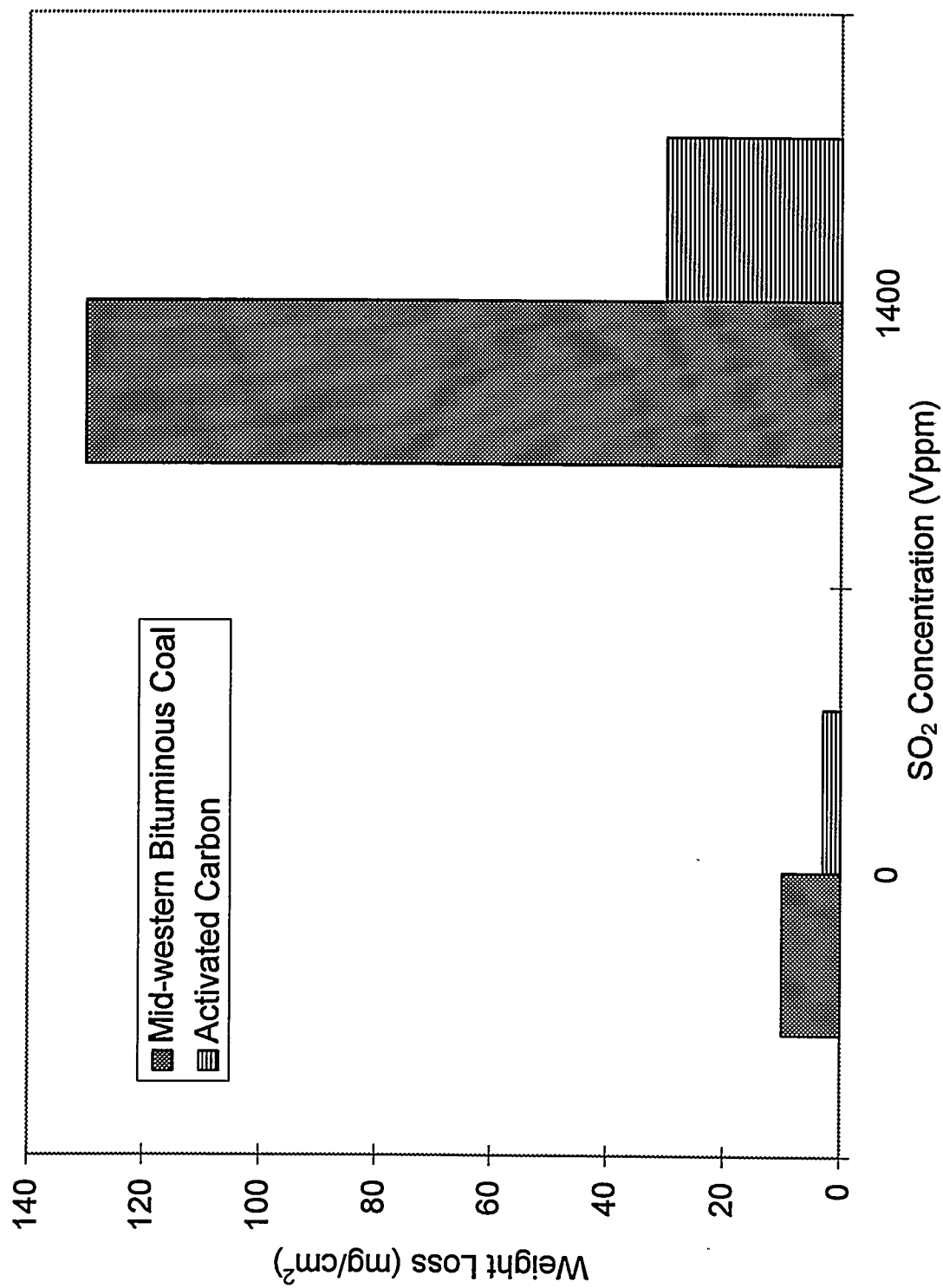


Figure 11 - Effect of sulfur dioxide on the metal recession for T-11 material at 500 °C.

Boiler Simulation Facility (BSF) Testing

The aim of this task was to confirm the relationship between gas constituents and corrosion morphology at waterwalls during substoichiometric coal firing. Corrosion and deposition probes were installed in the BSF during the evaluation of various firing configurations arranged to optimize the reduction of NO_x emissions. The probes were located at taps 46 and 41 at the elevation above the close coupled overfire air (CCOFA) and below the separated overfire air (SOFA) elevation (Figure 12). Measurements of gaseous species at the waterwalls adjacent to these taps were monitored during a four (4) hour exposure period.

Table 4 lists the normalized gas composition measured at taps 41 (deposition probe) and 46 (corrosion probe) for three coal firing configurations. A mid-western bituminous coal containing 2.5% sulfur was used during the combustion tests.

The gas measured at tap 41 for all firing conditions is essentially composed of oxidized forms of sulfur (SO₂) and carbon (CO₂) with minor concentrations of CO and TRS. However, the gas at tap 46 for the TFS 2000™ firing condition contains appreciable quantities of CO and TRS making it a potentially reducing gas which can be detrimental in terms of corrosion for low alloy steels. The composition of the gas measured at tap 46 under main burner zone stoichiometric ratios of 1.2 and 1.0 conditions is comparable to that measured in tap 41.

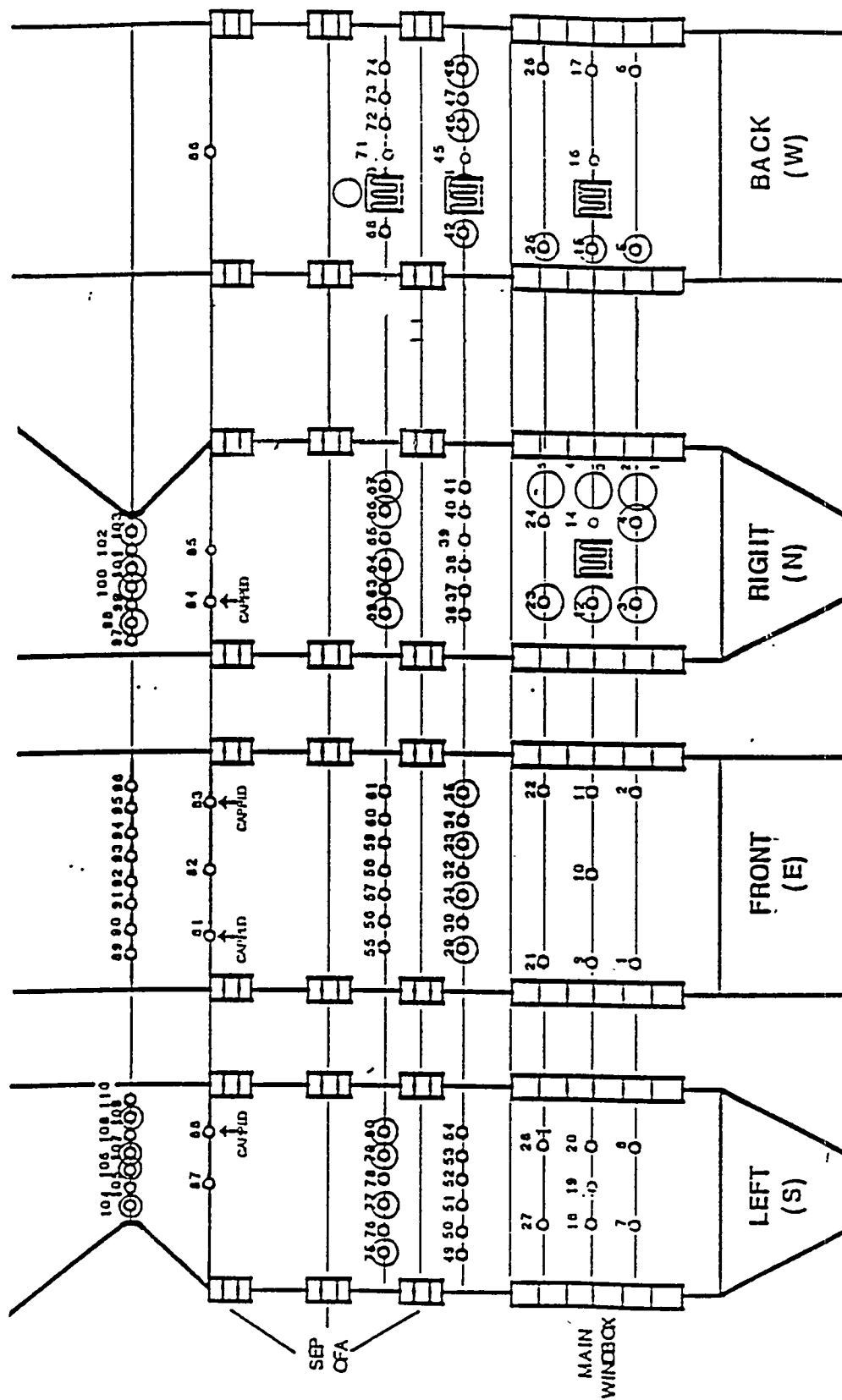


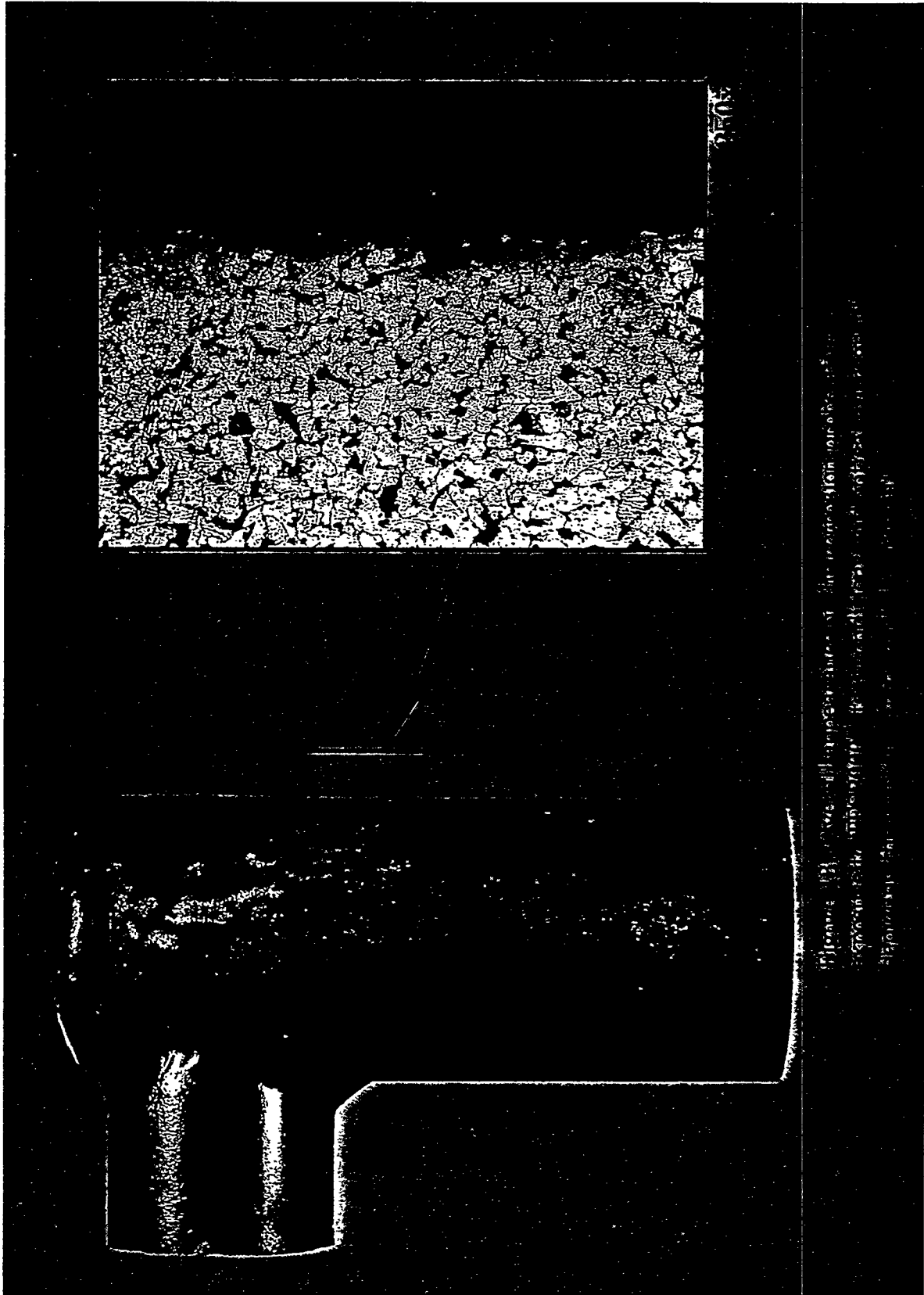
Figure 12 Diagram of the Boiler Simulation Facility showing the tap locations

Table 4 Normalized Gas Compositions Measured at BSF Taps 41 and 46 Adjacent to The Deposition Probe and Corrosion Probe

Firing Configuration	Tap 41 Deposition Probe	Tap 46 Corrosion Probe
main burner zone stoichiometric ratio 1.2	164 ppm CO 2.56 ppm TRS 1738 ppm SO ₂ 15.63% CO ₂	2525.47 ppm CO 2.92 ppm TRS 1576 ppm SO ₂ 15.31% CO ₂
main burner zone stoichiometric ratio 0.9 to 1.0	269.42 ppm CO 1.74 ppm TRS 1573 ppm SO ₂ 14.15% CO ₂	79.18 ppm CO 1.90 ppm TRS 1857 ppm SO ₂ 16.36% CO ₂
main burner zone stoichiometric ratio 0.7	2.03% CO 27.53 ppm TRS 1831 ppm SO ₂ 13.73% CO ₂	6.31% CO 825.06 ppm TRS 1132 ppm SO ₂ 12% CO ₂

Upon exposure to main burner zone stoichiometric ratio of 1.2 conditions the corrosion product formed on bare T-11 was an oxide of Fe as indicated by the EDS analysis. Iron oxide formation was expected upon exposure of T-11 to the type of gas measured at tap 46 during this type of firing configuration as predicted from thermodynamic stability diagrams. The corrosion product was present as a continuous scale and as incipient intergranular attack. The T-11 chromized sample did not show any apparent degradation with the Cr-carbide surface layer intact.

The bare T-11 corrosion probe exposed to the 0.7 main burner zone stoichiometric ratio firing conditions at tap 46 showed susceptibility to high temperature sulfidation. The overall appearance of the probe is shown in Figure 13. A detailed examination of



the corrosion product is given in Figure 14. Adjacent to the metal a scale of iron sulfide was formed, and on top of the sulfide layer an apparently porous iron-oxide was formed with entrained particulate. The entrained ash particulate has spherical shape and was rich in Si, Al, and Ca.

The formation of intercalated sulfides and oxides of iron reflects fluctuating sulfidizing/oxidizing gas conditions. Porous oxide or sulfide layers reflect fast growth which is commonly associated with flame impingement.

Under the 1.0 main burner zone stoichiometric ratio firing conditions, the corrosion product formed on T-11 was an Fe-oxide as evidenced by the EDS analysis. The degradation front was irregular with discrete intergranular penetration and the formation of iron oxide was concomitant with the oxidizing gas measured in the neighborhood of the corrosion probe.

Additional BSF testing included near wall gas species (*i.e.*, TRS and CO) measurements which have been previously related to corrosion potential. These measurements were performed on the helical firing arrangement in the main burners, *i.e.* each adjacent burner was arranged with the air entering at successively higher elevations and with lower air stoichiometries with each successive test run. In all of these runs, the overfire air (SOFA) was introduced at the C elevation closest to the upper main burner elevation. During the fourth test run, the SOFA was introduced at a more separated B elevation. Table 5 summarizes the gas sampling results at selected elevations.

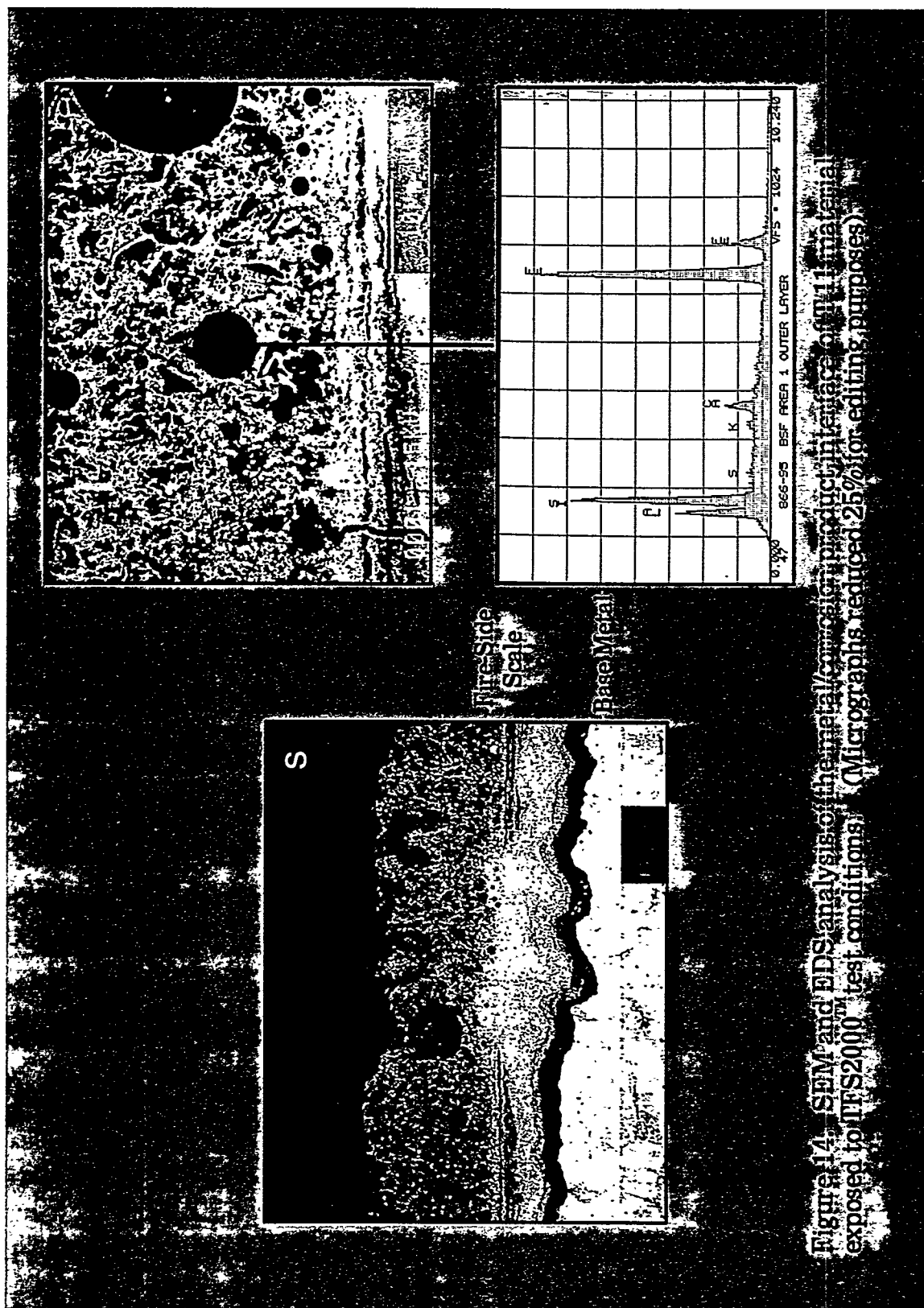


Figure 14. SEM and EDS analysis of the metal/composite product interface of the material exposed to IFS2000™ test conditions. (Micrographs reduced 25% for editing purposes)

Table 5 Gas Sampling at Selected Elevations During
Helical Firing Conditions

Test Number	126	127	128	134
SOFA Location	C			B
Main Burner Stoichiometry Planned (Actual)	0.9 (0.83)	0.7 (0.64)	0.55 (0.52)	0.7 (0.65)
Ports at Main Burner TRS (ppm) CO (%)	2.6 0.14	13.0 0.99	38.0 2.8	46.6 2.3
Ports between SOFA C and Main Burner TRS (ppm) CO (%)	3.7 1.1	44.3 2.9	8.0 0.5	461 5.0
Ports between SOFA B and C TRS(ppm) CO (%)	1.7 0.17	39.0 1.5	21.0 1.1	280 3.9
Outlet NO _x (ppm) lb/MMBtu	230 0.31	149 0.21	152 0.21	109 0.15

At the main burner zone, TRS and CO generally increased with decreasing stoichiometry. When SOFA B was used, the NO_x was 33% lower than with SOFA C arrangements at 0.7 main burner stoichiometry. The TRS at the highest sampling port elevation was greater, thus representing a greater corrosion potential.

Figure 15 shows a plot of the measured TRS concentration as a function of the CO values. The results show a good correlation between CO and TRS. The data is also supported by the analytical results of the particulate samples collected at the furnace walls. Review of the carbon and sulfur analyses obtained on particulate samples collected during each of the four test runs shows relatively similar carbon levels (32-34%) in both 0.5 and 0.7 air stoichiometries but only 13% in the run with 0.9 stoichiometry. These results clearly show the CO levels track TRS confirming that the potential for wastage generally increases with increasing CO concentration.

Heat Transfer Conditions Tests

Accelerated metal degradation can take place under conditions where the component is exposed to high heat fluxes. The gaseous environment can be reducing due to the local consumption of oxygen rendering the material more susceptible to attack by reduced gas species. Localized steep temperature gradients can also cause an increase in the surface metal temperature that in turns results in faster degradation rates.

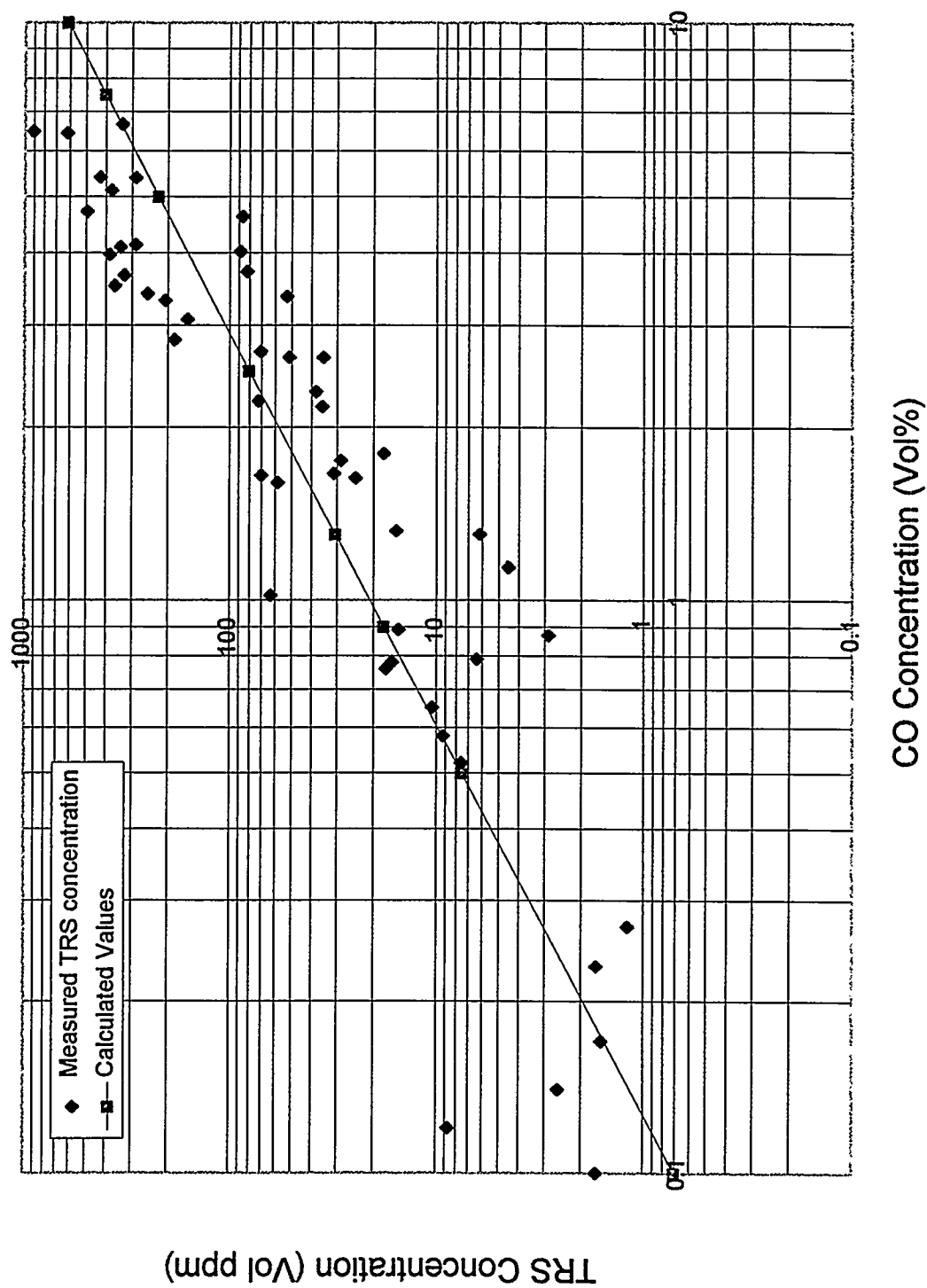


Figure 15. Correlation between TRS and CO concentration in gas measured with helical firing configuration during BSF test (Jan18-20, 1996).

A dedicated test facility was assembled at ABB where bare T-11 and chromized T-11 test pieces were cooled with compressed air while the testing gas was kept at a higher temperature. The test pieces were exposed up to 500 hr and the overall metal recession was determined from metallographic cross-sections. Table 6 lists the composition of the gases used during the tests.

Table 6 Gas Compositions Used in Heat Transfer Corrosion Tests

Oxidizing Gas	Reducing Gas
1000 ppm SO ₂	1000 ppm H ₂ S
12.3% CO ₂	7% CO ₂
8.6% CO	13% CO
2.44% H ₂	2% H ₂
0.68% O ₂	0% O ₂
N ₂ balance	N ₂ balance

Isothermal testing using oxidizing gas conditions at 500°C resulted in the formation of an oxide scale on bare T-11 material with sulfide formation at the scale/metal interface. Upon exposure to the oxidizing gas, the formation of iron-oxide is the thermodynamically favored process. At the metal/scale interface, the oxygen partial pressure corresponds to that of the Fe-Fe₃O₄ equilibrium. As oxidation proceeds, growth stresses in the scale can lead to microcracking, allowing access of SO₂ to the

interface and a local build up of sulfidizing species takes place by the decomposition of the SO_2 molecule, shifting the local conditions to the $\text{FeS-Fe}_3\text{O}_4\text{-Fe}$ equilibrium. After 500 hr of exposure an average material recession of $25.4\text{ }\mu\text{m}$ was obtained.

Under heat transfer conditions the corrosion product formed on bare T-11 material was an Fe-sulfide with metal losses of 279 to $406\text{ }\mu\text{m}$ after 466 hr of exposure. The metal temperature was about $500\text{ }^\circ\text{C}$ and the gas temperature was around $1200\text{ }^\circ\text{C}$.

Thermochemical analysis of the gas as a function of temperature suggest a reducing gas condition at the metal temperature concomitant with the reaction product formed on the test piece surface.

No measurable wastage was observed with the chromized T-11 under oxidizing conditions at both isothermal and heat transfer testing conditions.

Tests conducted with bare T-11 isothermally at $500\text{ }^\circ\text{C}$ with the reducing gas mixture resulted in a metal loss of 89 microns after a 500 hr exposure with the formation of Fe-sulfide scales. After exposure for a similar period of time under heat transfer conditions, a metal loss of 457 to $559\text{ }\mu\text{m}$ was measured.

The data clearly suggest that under heat transfer conditions, an increase potential for accelerated wastage exists under both oxidizing and reducing gas conditions due to a high-temperature sulfidation mechanism.

Conclusions

- Deep staged firing conditions can lead to localized reducing environments conducive to material degradation by high-temperature sulfidation. However, a proper firing system design can minimize localized reducing environments and unburned carbon adjacent to the furnace walls.
- Increased total reduced sulfur species and CO coincide with an increase in carbon and sulfur concentration in the particulate arriving at waterwalls, increasing the susceptibility for accelerated wastage due to a reducing microclimate effect.
- SA-213 grade T-11 steel was susceptible to high-temperature sulfidation under localized reducing conditions. The kinetics of sulfidation for T-11 material followed a sublinear rate with a larger wastage rate than 310 SS while chromized T-11 was superior.
- Under heat transfer conditions, a localized high temperature gradient exacerbated wastage rates caused by high-temperature sulfidation under either oxidizing or reducing gases.
- During helical firing configurations, the greater SOFA separation resulted in more reducing conditions with an increasing susceptibility for accelerated wastage due to sulfidizing gas attack.

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